

May 12, 2006

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

RE: D.T.E. 04-116

Dear Secretary Cottrell:

On behalf of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, I am enclosing a supplemental response to Information Request DTE-MECo 1-5 in the Department's First Set of Information Requests to Massachusetts Electric Company.

Thank you for your time and attention to this matter.

Very truly yours,


Amy G. Rabinowitz

cc: Service List

Information Request DTE-MECo 1-5 - Supplement

Request:

Please identify each and every state, commonwealth, or federal district that has adopted IEEE 1366-2003 in some form for reporting purposes for all electric distribution companies within its jurisdiction. (Do not include any state, commonwealth, or federal district that has adopted a variation or part of IEEE 1366-2003 for one, two or a few companies but not for all.) Explain the difference between what was adopted in these states, commonwealths, or federal district and what is proposed in this docket. For each and every state, commonwealth, and federal district, identified, provide copies of the enabling legislation, Order, or regulation adopting IEEE 1366-2003.

Response:

In addition to the information included in our original response to this question submitted to the Department on May 3, 2006, the Company has received information on two additional jurisdictions that have adopted the IEEE Std.1366-2003 as described in question 1-5.

Please find attached to this response the Rules Regulating Electric Utilities from the Colorado Public Utilities Commission (CPUC), which indicates in Section 3250 that Colorado utilities are required to report major events to the CPUC using the IEEE Std. 1366-2003 definition.

In addition, please find attached to this response Order Number 13565 from the Public Service Commission of the District of Columbia adopting the Customer Service and Reliability Standards Report (also attached), which recommends a change in the definition of major events to the IEEE Std. 1366-2003 method for the Potomac Electric Power Company, the only distribution company in Washington, D.C.

Prepared by or under the supervision of: Cheryl A. Warren

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 CODE OF COLORADO REGULATIONS (CCR) 723-3

PART 3

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BASIS, PURPOSE, AND STATUTORY AUTHORITY.

The basis and purpose of these rules is to describe the electric service to be provided by jurisdictional utilities and master meter operators to their customers; to designate the manner of regulation over such utilities and master meter operators; and to describe the services these utilities and master meter operators shall provide. In addition, these rules identify the specific provisions applicable to public utilities or other persons over which the Commission has limited jurisdiction. These rules address a wide variety of subject areas including, but not limited to, service interruption, meter testing and accuracy, safety, customer information, customer deposits, rate schedules and tariffs, discontinuance of service, master meter operations, flexible regulation, cost allocation between regulated and unregulated operations, recovery of costs, small power producers and cogeneration facilities, and appeals regarding local government land use decisions. The statutory authority for these rules can be found at §§ 29-20-108, 40-1-103.5, 40-2-108, 40-3-102, 40-3-103, 40-3-104.3, 40-3-111, 40-3-114, 40-4-101, 40-4-106, 40-4-108, 40-4-109, 40-5-103, and 40-9.5-107(5), C.R.S.

GENERAL PROVISIONS

3000. Scope and Applicability.

- (a) Absent a specific statute, rule, or Commission Order which provides otherwise, all rules in this Part 3 (the 3000 series) shall apply to all jurisdictional electric utilities and electric master meter operators and to Commission proceedings concerning electric utilities or electric master meter operators providing electric service.
- (b) The following rules in this Part 3 shall apply to **cooperative electric associations which have elected to exempt themselves from the Public Utilities Law** pursuant to § 40-9.5-103 C.R.S.:
 - (I) Rules 3002 (a)(I), (a)(II), (a)(IV), (a)(V), (a)(XVI), (b), and (c) concerning the filing of applications for certificate of public convenience and necessity for franchise or service territory, for certificate amendments, to merge or transfer, or for appeals of local land use decisions.
 - (II) Rules 3005 (a)(III) (IV), (d), (e), (g), and (h) concerning records under RUS accounting system and preservation of records.
 - (III) Rule 3006 (a) (b) (c) (d) and (e) concerning the filing of annual reports, designation for service of process, and election of applicability of Title 40, Article 8.5.
 - (IV) Rules 3008 (b) and (d) concerning incorporation by reference.

- (V) Rules 3100 and 3103 concerning application for and amendment of a certificate of public convenience and necessity relating to a franchise.
 - (VI) Rules 3101 and 3103 concerning application for and amendment of a certificate of public convenience and necessity relating to service territory.
 - (VII) Rule 3104 concerning application to transfer assets, to obtain a controlling interest, or to merge with another entity.
 - (VIII) Rule 3204 concerning incidents occurring in connection with the operation of facilities.
 - (IX) Rule 3207 (a) and (b), concerning construction and expansion of distribution facilities.
 - (X) Rules 3250 through 3253 concerning major event reporting.
 - (XI) Rules 3700 through 3707 concerning appeals of local governmental land use decisions actions.
- (c) The following rules in this Part 3 shall apply to **cooperative electric generation and transmission associations**:
- (I) Rules 3002 (a)(III), (a)(XVI), (b), and (c) concerning the filing of applications for certificates of public convenience and necessity for facilities or for appeals of local land use decisions.
 - (II) Rule 3006(h) concerning the filing of least-cost planning reports.
 - (III) Rule 3102 concerning applications for certificates of public convenience and necessity for facilities.
 - (IV) Rule 3103 concerning amendments to certificates of public convenience and necessity for facilities.
 - (V) Rule 3104 concerning application to transfer, to obtain a controlling interest, or to merger with another entity.
 - (VI) Rule 3200 concerning construction, installation, maintenance, and operation of facilities.
 - (VII) Rule 3204 concerning incidents occurring in connection with the operation of facilities.
 - (VIII) Rule 3205 concerning construction or expansion of generating capacity.
 - (IX) Rule 3206 concerning construction or extension of transmission facilities.
 - (X) Rule 3253(a) concerning major event reporting.
 - (XI) Rules 3602, 3605, and 3614(a) concerning least-cost resource planning.

- (XII) Rules 3700 through 3707 concerning appeals of local governmental land use decisions actions.

3001. Definitions.

The following definitions apply throughout this Part 3, except where a specific rule or statute provides otherwise. In addition to the definitions stated here, the definitions found in the Public Utilities Law apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Affiliate" of a public utility means a subsidiary of a public utility, a parent corporation of a public utility, a joint venture organized as a separate corporation or partnership to the extent of the individual public utility's involvement with the joint venture, a subsidiary of a parent corporation of a public utility or where the public utility or the parent corporation has a controlling interest over an entity.
- (b) "Applicant for service" means a person who applies for utility service and who either has taken no previous utility service from that utility or has not taken utility service from that utility within the most recent 30 days.
- (c) "Average error" means the arithmetic average of the percent registration at light load and at heavy load, giving the heavy load registration a weight of four and the light load registration a weight of one.
- (d) "Basis Point" means one-hundredth of a percentage point (100 basis points = 1%).
- (e) "Benefit of service" means the use of utility service by each person of legal age who resides at a premises to which service is delivered and who is not registered with the utility as the customer of record.
- (f) "Commission" means the Colorado Public Utilities Commission.
- (g) "Customer" means any person who is currently receiving utility service. Any person who moves within a utility's service territory and obtains utility service at a new location within 30 days shall be considered a "customer." Unless stated in a particular rule, "customer" applies to any class of customer as defined by the Commission or by utility tariff.
- (h) "Creep" means that, with all load wires disconnected, a meter's moving element makes one complete revolution in ten minutes or less.
- (i) "Distribution extension" is any construction of distribution facilities, including primary and secondary distribution lines, transformers, service laterals, and appurtenant facilities (except meters and meter installation facilities), necessary to supply service to one or more additional customers.
- (j) "Distribution facilities" are those lines designed to operate at the utility's distribution voltages in the area as defined in the utility's tariffs including substation transformers that transform electricity to a distribution voltage and also includes other equipment within a transforming substation which is not integral to the circuitry of the utility's transmission system.

- (k) "Energy assistance organization" means the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.
- (l) "Heavy load" means not less than 60 percent, but not more than 100 percent, of the nameplate-rated capacity of a meter.
- (m) "Informal complaint" means an informal complaint as defined and discussed in the Commission's Rules Regulating Practice and Procedure.
- (n) "Light load" means approximately five to ten percent of the nameplate-rated capacity of a meter.
- (o) "Load" means the power consumed by an electric utility customer over time (measured in terms of either demand or energy or both).
- (p) "Local office" means any Colorado office operated by a utility at which persons may make requests to establish or to discontinue utility service. If the utility does not operate an office in Colorado, "local office" means any office operated by a utility at which persons may make requests to establish or to discontinue utility service in Colorado.
- (q) "Main service terminal" means the point at which the utility's metering connections terminate. Main service terminals are accessed by removing the meter dial face from the meter housing.
- (r) "MVA" means mega-volt amperes and is the vector sum of the real power and the reactive power.
- (s) "Output" means the energy and power produced by a generation system.
- (t) "Past due" means the point at which a utility can affect a customer's account for regulated service due to non-payment of charges for regulated service.
- (u) "Principal place of business" means the place, in or out of the State of Colorado, where the executive or managing principals who directly oversee the utility's operations in Colorado are located.
- (v) "Reference standard" means suitable indicating electrical equipment permanently mounted in a utility's laboratory and used for no purpose other than testing rotating standards.
- (w) "Regulated charges" means charges billed by a utility to a customer if such charges are approved by the Commission or contained in a tariff of the utility.
- (x) "Rotating standard" means a portable meter used for testing service meters.
- (y) "RUS" means the Rural Utilities Service of the United States Department of Agriculture, or its successor agencies.
- (z) "Security" includes any stock, bond, note, or other evidence of indebtedness.
- (aa) "Service connection" is the location on the customer's premises/facilities at which a point of delivery of power between the utility and the customer is established. For example, in the case of a typical residential customer served from overhead secondary supply, this is the location at

which the utility's electric service drop conductors are physically connected to the customer's electric service entrance conductors.

- (bb) "Staff" means Staff of the Public Utilities Commission.
- (cc) "Transmission extension" is any construction of transmission facilities and appurtenant facilities, including meter installation facilities (except meters), which is connected to and enlarges the utility's transmission system and which is necessary to supply transmission service to one or more additional customers.
- (dd) "Transmission facilities" are those lines and related substations designed and operating at voltage levels above the utility's voltages for distribution facilities, including but not limited to related substation facilities such as transformers, capacitor banks, or breakers that are integral to the circuitry of the utility's transmission system.
- (ee) "Unregulated charges" means charges that are billed by a utility to a customer and that are not regulated or approved by the Commission, are not contained in a tariff filed with the Commission, and are for service or merchandise not required as a condition of receiving regulated utility service.
- (ff) "Utility" means any public utility as defined in § 40-1-103, C.R.S., providing electric, steam, or associated services in the state of Colorado.
- (gg) "Utility service" or "service" means a service offering of a public utility, which service offering is regulated by the Commission.

3002. Applications.

- (a) By filing an appropriate application, any utility may ask that the Commission take action regarding any of the following matters:
 - (I) For the issuance or extension of a certificate of public convenience and necessity for a franchise, as provided in rule 3100.
 - (II) For the issuance or extension of a certificate of public convenience and necessity for service territory, as provided in rule 3101.
 - (III) For the issuance of a certificate of public convenience and necessity for construction of facilities, as provided in rule 3102.
 - (IV) For the amendment of a certificate of public convenience and necessity in order to change, extend, curtail, abandon, or discontinue any service or facility, as provided in rule 3103.
 - (V) To transfer a certificate of public convenience and necessity, to obtain a controlling interest in any utility, to transfer assets within the jurisdiction of the Commission or stock, or to merge a utility with another entity, as provided in rule 3104.

- (VI) For approval of the issuance, or assumption of any security or to create a lien pursuant to § 40-1-104, as provided in rule 3105.
 - (VII) For flexible regulatory treatment to provide service without reference to tariffs, as provided in rule 3106.
 - (VIII) For approval of an air quality improvement program, as provided for in rule 3107.
 - (IX) To amend a tariff on less than statutory notice, as provided in rule 3109.
 - (X) For variance of voltage standards, as provided in rule 3202.
 - (XI) For approval of meter and equipment testing practices, as provided in rule 3303.
 - (XII) For approval of a meter sampling program, as provided in rule 3304.
 - (XIII) For approval of a refund plan, as provided in rule 3410.
 - (XIV) For approval of a cost assignment and allocation manual, as provided in rule 3503.
 - (XV) For approval of or for amendment to a least-cost resource plan, as provided in rules 3603, 3613, and 3615.
 - (XVI) For appeal of local government land use decision, as provided in rule 3703.
 - (XVII) For any other matter not specifically described in this rule, unless such matter is required to be submitted as a petition under rule 1304, as a motion, or as some other specific type of submittal.
- (b) In addition to the requirements of specific rules, all applications shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:
- (I) The name and address of the applying utility.
 - (II) The name(s) under which the applying utility is, or will be, providing service in Colorado.
 - (III) The name, address, telephone number, facsimile number, and e-mail address of the applying utility's representative to whom all inquiries concerning the application should be made.
 - (IV) A statement that the applying utility agrees to answer all questions propounded by the Commission or its Staff concerning the application.
 - (V) A statement that the applying utility shall permit the Commission or any member of its Staff to inspect the applying utility's books and records as part of the investigation into the application.

- (VI) A statement that the applying utility understands that, if any portion of the application is found to be false or to contain material misrepresentations, any authorities granted pursuant to the application may be revoked upon Commission order.
 - (VII) In lieu of the separate statements required by subparagraphs (b)(IV) through (VI) of this rule, a utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(IV) through (VI) of this rule.
 - (VIII) A statement describing the applying utility's existing operations and general service area in Colorado.
 - (IX) For applications listed in subparagraphs (a)(I), (II), (III), (V), and (VI) of this rule, a copy of the applying utility's or parent company's and consolidated subsidiaries' most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows so long as they provide Colorado specific financial information.
 - (X) A statement indicating the town or city, and any alternative town or city, in which the applying utility prefers any hearings be held.
 - (XI) Acknowledgment that, by signing the application, the applying utility understands that:
 - (A) The filing of the application does not by itself constitute approval of the application.
 - (B) If the application is granted, the applying utility shall not commence the requested action until the applying utility complies with applicable Commission rules and any conditions established by Commission order granting the application.
 - (C) If a hearing is held, the applying utility must present evidence at the hearing to establish its qualifications to undertake, and its right to undertake, the requested action.
 - (D) In lieu of the statements contained in subparagraphs (b)(XI)(A) through (C) of this rule, an applying utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(XI)(A) through (C) of this rule.
 - (XII) A statement which is made under penalty of perjury; which is signed by an officer, a partner, an owner, an employee of, an agent for, or an attorney for the applying utility, as appropriate, who is authorized to act on behalf of the applying utility; and which states that the contents of the application are true, accurate, and correct. The application shall contain the title and the complete address of the affiant.
- (c) In addition to the requirements of specific rules, all applications either shall include the following items or shall incorporate the following items by referring to information on file with the Commission in a miscellaneous docket created for that purpose. Applying utilities choosing to keep an item on file with the Commission in such miscellaneous docket shall keep the most current version on file and shall state in the application when the item was last filed with the Commission. Applying utilities choosing to include an item with the application shall include it in

the following order and specifically identified either in the application or in appropriately identified attached exhibits:

- (I) A copy of the applying utility's applicable organizational documents (e.g., Articles of Incorporation, Partnership Agreement, Articles of Organization).
- (II) If the applying utility is not organized in Colorado, a current copy of the certificate issued by the Colorado Secretary of State authorizing the applying utility to transact business in Colorado.
- (III) The name, business address, and title of each officer, director, and partner.
- (IV) The names and addresses of affiliated companies that conduct business with the Colorado utility.
- (V) The name and address of the applying utility's Colorado agent for service of process.

3003. [Reserved]

3004. Disputes and Informal Complaints.

- (a) For purposes of this rule, "dispute" means a concern, difficulty, or problem which needs resolution and which a customer or a person applying for service brings directly to the attention of the utility without the involvement of Staff or the Commission.
- (b) A dispute may be initiated orally or in writing. Using the procedures found in rule 1301, a utility shall conduct a full and prompt investigation of all disputes concerning utility service.
- (c) In accordance with the procedures in rule 1301, each utility shall conduct a full and prompt investigation of all informal complaints concerning utility service.
- (d) A utility shall comply with all rules regarding the timelines for responding to informal complaints.
- (e) If a current customer, or an applicant for service that is not a current customer, is dissatisfied with the utility's proposed adjustment or disposition of a dispute, the utility shall inform the person, customer or applicant for service of the right to make an informal complaint to the External Affairs section of the Commission and shall provide to the person, customer or applicant for service the address and toll free number of the Commission's External Affairs section.
- (f) Each utility shall keep a record of each informal complaint and of each dispute. The record shall show the name and address of the initiating customer or person applying for service, the date and character of the issue, and the adjustment or disposition made. This record shall be open at all times to inspection by the person who initiated the informal complaint or dispute, by the Commission, and by Staff.

3005. Records.

- (a) Except as a specific rule may require, every utility shall maintain, for a period of not less than three years, and shall make available for inspection at its principal place of business during regular business hours, the following:
 - (I) Records concerning disputes and informal complaints, which records are created pursuant to rule 3004.
 - (II) Records of daily load and monthly plant output, which records are created pursuant to rule 3201.
 - (III) Records of service voltage measurements, which records are created pursuant to rule 3202(a).
 - (IV) Records concerning interruptions of service, which records are created pursuant to rule 3203.
 - (V) Records concerning certification and calibration of meter testing equipment, which records are created pursuant to rule 3303.
 - (VI) Records concerning meter testing upon customer request, which records are created pursuant to rule 3305.
 - (VII) Records concerning meters and their associated testing, which records are created pursuant to rule 3306.
 - (VIII) Customer billing records, which records are created pursuant to rule 3401(a).
 - (IX) Customer deposit records, which records are created pursuant to rule 3403.
 - (X) Records and supporting documentation concerning its cost assignment and allocation manual and fully-distributed cost study pursuant to rules 3503(g) and 3504(e), for so long as the manual and study are in effect or are the subject of a complaint or a proceeding before the Commission.
 - (XI) Records concerning the utility's inspection of Qualifying Facilities, which records are created pursuant to rules 3927(c) and (e).
- (b) A utility shall maintain at each of its local offices and at its principal place of business all tariffs filed with the Commission and applying to Colorado rate areas. If the utility maintains a website, it shall also maintain its current and complete tariffs on its website.
- (c) Each utility shall maintain its books of account and records in accordance with the provisions of 18 C.F.R. Part 101, the Uniform System of Accounts, amended as of April 1, 2005. A utility shall maintain its books of accounts and records separately from those of its affiliates.

- (d) Each cooperative electric association which is a RUS borrower shall maintain its books of account and records in accordance with the provisions of 7 C.F.R. Part 1767, effective as of January 1, 2005.
- (e) Each non-RUS borrower cooperative electric association shall maintain its books of account and records either consistent with the provisions of 18 C.F.R. Part 125, effective as of April 1, 2004, or consistent with the provisions of 7 C.F.R. Part 1767, effective as of January 1, 2005.
- (f) Each utility shall preserve its records in accordance with the provisions of 18 C.F.R. Part 125, the Preservation of Records of Public Utilities and Licensees, amended as of April 1, 2005.
- (g) Each cooperative electric association that is a RUS borrower shall preserve its records in accordance with the provisions of Rural Utilities Service Bulletin 180-2, effective June 26, 2003.
- (h) Each non-RUS borrower cooperative electric association shall preserve records consistent with the provisions of 18 C.F.R. Part 101, effective as of April 1, 2004.

3006. Reports.

- (a) On or before April 30th of each year, each utility shall file with the Commission an annual report for the preceding calendar year. The utility shall submit the annual report on forms prescribed by the Commission; shall properly complete the forms; and shall ensure the forms are verified and signed by a person authorized to act on behalf of the utility. If the Commission grants the utility an extension of time to file the annual report, the utility nevertheless shall file with the Commission, on or before April 30, the utility's total gross operating revenue from intrastate utility business transacted in Colorado for the preceding calendar year.
- (b) If a utility publishes an annual report or an annual statistical report to stockholders, other security holders or members, or if it receives an annual certified public accountant's report of its business, the utility shall file one copy of the report with the Commission within 30 days after publication or receipt of such report.
- (c) A cooperative electric association shall file with the Commission a report listing its designation of service.
- (d) A cooperative electric association shall file with the Commission a report of election to be governed by § 40-8.5-102, C.R.S., pertaining to unclaimed monies. This report shall be filed within 60 days of the election.
- (e) Pursuant to rule 3204, a utility shall file with the Commission a report concerning any incident which results in death, serious injury, or significant property damage.
- (f) Pursuant to rules 3252 and 3253, a utility shall file with the Commission a report concerning any major event.
- (g) Pursuant to rules 3503(a), 3504(a), and 3503(i), a utility shall file with the Commission cost assignment and allocation manuals, fully-distributed cost studies, and required updates.

- (h) Pursuant to rule 3614(a), a utility shall file with the Commission an annual progress report concerning the utility's least-cost resource plan.
- (i) Pursuant to rule 3614(b), a utility shall file with the Commission reports on competitive acquisition bidding of the utility's least-cost resource plan.
- (j) A utility shall file with the Commission any report required by a rule in this 3000 series of rules.
- (k) A utility shall file with the Commission such special reports as the Commission may require.

3007. [Reserved]

3008. Incorporation by Reference.

- (a) The Commission incorporates by reference 18 C.F.R. Part 101 (as published on April 1, 2005) regarding the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. No later amendments to or editions of 18 C.F.R. Part 101 are incorporated into these rules.
- (b) The Commission incorporates by reference 7 C.F.R. Part 1767 (as published on January 1, 2005) regarding the Uniform System of Accounts Prescribed for RUS Electric Borrowers. No later amendments to or editions of 7 C.F.R. Part 1767 are incorporated into these rules.
- (c) The Commission incorporates by reference 18 C.F.R. Part 125 (as published on April 1, 2005) regarding the Preservation of Records of Public Utilities and Licensees. No later amendments to or editions of 18 C.F.R. Part 125 are incorporated into these rules.
- (d) The Commission incorporates by reference RUS Bulletin 180-2 (as published on June 26, 2003) regarding Record Retention Recommendations for RUS Electric Borrowers. No later amendments to or editions of RUS Bulletin 180-2 are incorporated into these rules.
- (e) The Commission incorporates by reference the National Electrical Safety Code, C2-2002 edition, published by the Institute of Electrical and Electronics Engineers and endorsed by the American National Standards Institute. No later amendments to or editions of the National Electrical Safety Code are incorporated into these rules.
- (f) The Commission incorporates by reference 18 C.F.R., Subchapter K, Part 292, Subparts A, B and C (as published on April 1, 2005) regarding §§ 201 and 210 of the Public Utility Regulatory Policies Act of 1978. No later amendments to or editions of 18 C.F.R., Subchapter K, Part 292, Subparts A, B and C are incorporated into these rules.
- (g) Any material incorporated by reference in this Part 3 may be examined at the offices of the Commission, 1580 Logan Street, OL-2, Denver, Colorado 80203, during normal business hours, Monday through Friday, except when such days are state holidays. Certified copies of the incorporated standards shall be provided at cost upon request. The Director or the Director's designee will provide information regarding how the incorporated standards may be examined at any state public depository library.

3009. - 3099. [Reserved]

OPERATING AUTHORITY

3100. Certificate of Public Convenience and Necessity for a Franchise.

- (a) A utility seeking authority to provide service pursuant to a franchise shall file an application pursuant to this rule. When a utility enters into a franchise agreement with a municipality for the first time, it shall obtain authority from the Commission pursuant to § 40-5-102, C.R.S. prior to providing service under that initial franchise agreement. A utility maintains the right and obligation to serve a municipality within its service territory after the expiration of any franchise agreement.
- (b) An application for certificate of public convenience and necessity to exercise franchise rights shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:
 - (I) The information required in rules 3002(b) and 3002(c).
 - (II) A statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application.
 - (III) A statement describing the franchise rights proposed to be exercised. The statement shall include a description of the type of utility service to be rendered and a description of the city or town sought to be served.
 - (IV) A certified copy of the franchise ordinance; proof of publication, adoption, and acceptance by the applying utility; a statement as to the number of customers served or to be served and the population of the city or town; and any other pertinent information.
 - (V) A statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the authority sought.
 - (VI) A copy of a feasibility study for areas previously not served by the applying utility, which study shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study.
 - (VII) A statement of the names of public utilities and other entities of like character providing similar service in or near the area sought to be served.

3101. Certificate of Public Convenience and Necessity for Service Territory.

- (a) A utility seeking authority to provide service in a new service territory shall file an application pursuant to this rule. A utility cannot provide service without authority from the Commission, unless the utility extends its facilities and service within a city and county or city or town within which the utility has lawfully commenced operations, or the utility extends its facilities and service into territory contiguous to the utility's facility, line, plant, or system that is not therefore served by a public utility providing the same commodity or service, or the utility extends its facilities and

service within or to territory already served by the utility and the extension is necessary in the ordinary course of business.

- (b) An application for certificate of public convenience and necessity to provide service in a new territory shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:
 - (I) The information required in rules 3002(b) and 3002(c).
 - (II) A statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application.
 - (III) A description of the type of utility service to be rendered and a description of the area sought to be served.
 - (IV) A map showing the specific geographic area that the applying utility proposes to serve. If the applying utility intends to phase in service in the territory over time, specific areas and proposed in-service dates shall be included. The map shall describe the geographic areas in section, township, and range convention.
 - (V) A statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the territory sought.
 - (VI) A statement of the names of public utilities and other entities of like character providing similar service in or near the area involved in the application.
 - (VII) A copy of a feasibility study for the proposed area to be served, which shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study.

3102. Certificate of Public Convenience and Necessity for Facilities.

- (a) A utility seeking authority to construct and to operate a facility or an extension of a facility pursuant to § 40-5-101, C.R.S., shall file an application pursuant to this rule. The utility need not apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is in the ordinary course of business. The utility shall apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is not in the ordinary course of business.
- (b) An application for certificate of public convenience and necessity to construct and to operate facilities or an extension of a facility pursuant to § 40-5-101, C.R.S., shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:
 - (I) The information required in rules 3002(b) and 3002(c).

- (II) A statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application or citation to any Commission decision that is relevant to the proposed facilities.
 - (III) A description of the proposed facilities to be constructed.
 - (IV) Estimated cost of the proposed facilities to be constructed.
 - (V) Anticipated construction start date, construction period, and in-service date.
 - (VI) A map showing the general area or actual locations where facilities will be constructed, population centers, major highways, and county and state boundaries.
 - (VII) As applicable, electric one-line diagrams.
 - (VIII) As applicable, information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate alternatives.
 - (IX) As applicable, a report of prudent avoidance measures considered and justification for the measures selected to be implemented.
 - (X) For transmission construction or extension, the information required by paragraph (c) of this rule.
- (c) For an application for a certificate of public convenience and necessity for construction or extension of transmission facilities, the applying utility shall describe its actions and techniques relating to cost-effective noise mitigation with respect to the planning, siting, construction, and operation of the proposed transmission construction or extension. The applying utility shall provide computer studies which show the potential noise levels expressed in db(A) and measured at the edge of the transmission line right-of-way. These computer studies shall be the output of utility standard programs, such as EPRI's EMF Workstation 2.51 ENVIRO Program -- Bonneville Power Administration model. The steps and techniques may include, without limitation, the following:
- (I) Bundled conductors.
 - (II) Larger conductors.
 - (III) Design alternatives considering the spatial arrangement of phasing of conductors.
 - (IV) Corona-free attachment hardware.
 - (V) Conductor quality.
 - (VI) Handling and packaging of conductor.
 - (VII) Construction techniques.
 - (VIII) Line tension.

- (d) For an application for a certificate of public convenience and necessity for construction or extension of transmission facilities, the applying utility shall describe its actions and techniques relating to prudent avoidance with respect to planning, siting, construction, and operation of the proposed construction or extension. As used in this paragraph, "prudent avoidance" means the striking of a reasonable balance between the potential health effects of exposure to magnetic fields and the cost and impacts of mitigation of such exposure, by taking steps to reduce the exposure at reasonable or modest cost. The steps and techniques may include, without limitation, the following:
 - (I) Design alternatives considering the spatial arrangement of phasing of conductors.
 - (II) Routing lines to limit exposures to areas of concentrated population and group facilities such as schools and hospitals.
 - (III) Installing higher structures.
 - (IV) Widening right of way corridors.
 - (V) Burying lines.

3103. Certificate Amendments for Changes in Service, in Service Territory, or in Facilities.

- (a) A utility seeking authority to do the following shall file an application pursuant to this rule: amend a certificate of public convenience and necessity in order to extend, to restrict, to curtail, or to abandon or to discontinue without equivalent replacement any service, service area, or facility. A utility cannot extend, restrict, curtail, or abandon or discontinue without equivalent replacement, any service, service area, or facility not in the ordinary course of business without authority from the Commission.
- (b) An application to amend a certificate of public convenience and necessity in order to change, to extend, to restrict, to curtail, to abandon, or to discontinue any service, service area, or facility without equivalent replacement shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:
 - (I) All information required in rules 3002(b) and 3002(c).
 - (II) If the application for amendment pertains to a certificate of public convenience and necessity for facilities, all of the information required in rule 3102.
 - (III) If the application for amendment pertains to a certificate of public convenience and necessity for franchise rights, all of the information required in rule 3100.
 - (IV) If the application for amendment pertains to a certificate of public convenience and necessity for service territory, all of the information required in rule 3101.
 - (V) If the application for amendment pertains to a service, the application shall include:
 - (A) The requested effective date for the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement of the service.

- (B) A description of the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement sought. This shall include maps, as applicable. This shall also include a description of the applying utility's existing operations and general service area.
- (c) In addition to complying with the notice requirements of the Commission's Rules Regulating Practice and Procedure, a utility applying to curtail, restrict, abandon or discontinue service without equivalent replacement shall prepare a written notice as provided in paragraph (d) of this rule and shall mail or deliver the notice at least 30 days before the application's requested effective date to each of the applying utility's affected customers. If no customers will be affected by the grant of the application, the notice shall be mailed to the Board of County Commissioners of each affected county, and to the mayor of each affected city, town, or municipality.
- (d) The notice required by paragraph (c) of the rule shall contain all of the following:
 - (I) The name of the applying utility.
 - (II) A statement detailing the requested restriction, curtailment, or abandonment or discontinuance without equivalent replacement and the requested effective date.
 - (III) A statement that any person may file a written objection with the Commission no later than ten days prior to the requested effective date; but that a written objection alone will not preserve any right to participate as a party in any Commission proceeding on the matter.
 - (IV) A statement that, in order to participate as a party, a person must file an appropriate and timely intervention according to the Commission's Rules Regulating Practice and Procedure.
 - (V) The Commission's full address.
- (e) Not later than 15 days before the requested effective date, the applying utility shall file with the Commission a written affidavit stating its compliance with the notice requirements of paragraphs (c) and (d) of this rule. The affidavit shall state the date the notice was completed and the method used to give notice. The applying utility shall attach a copy of the notice to the affidavit.

3104. Transfers, Controlling Interest, and Mergers.

- (a) A utility seeking authority to do any of the following shall file an application pursuant to this rule: transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in a utility, whether the transfer of control is effected by the transfer of assets, by the transfer of stock, by merger or by other form of business combination; or transfer assets subject to the jurisdiction of the Commission outside the normal course of business. A utility cannot transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in any utility; or transfer assets outside the normal course of business without authority from the Commission.
- (b) An application to transfer a certificate of public convenience and necessity, to transfer or obtain a controlling interest in a utility, or to transfer assets subject to the jurisdiction of the Commission

shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:

- (I) The information required in rules 3002(b) and 3002(c), as pertinent to each party to the transaction.
 - (II) A statement showing accounting entries, under the Uniform System of Accounts, including any plant acquisition adjustment, gain, or loss proposed on the books by each party before and after the transaction which is the subject of the application.
 - (III) Copies of any agreement for merger, sales agreement, or contract of sale pertinent to the transaction which is the subject of the application.
 - (IV) Facts showing that the transaction which is the subject of the application is not contrary to the public interest.
 - (V) An evaluation of the benefits and detriments to the customers of each party and to all other persons who will be affected by the transaction which is the subject of the application.
 - (VI) A comparison of the kinds and costs of service rendered before and after the transaction which is the subject of the application.
- (c) An application to transfer a certificate of public convenience and necessity, an application to transfer assets subject to the jurisdiction of the Commission, or an application to transfer or obtain control of the utility may be made by joint or separate application of the transferor and the transferee.
- (d) When control of a utility is transferred to another entity, or the utility's name is changed, the utility which will afterwards operate under the certificate of public convenience and necessity shall file with the Commission a tariff adoption notice, shall post the tariff adoption notice in a prominent public place in each local office and principal place of business of the utility, and shall have the tariff adoption notice available for public inspection at each local office and principal place of business. Adoption notice forms are available from the Commission. The tariff adoption notice shall contain all of the following information:
- (I) The name, phone number, and complete address of the adopting utility.
 - (II) The name of the previous utility.
 - (III) The number of the tariff adopted and the description or title of the tariff adopted.
 - (IV) The number of the tariff after adoption and the description or title of the tariff after adoption.
 - (V) Unless otherwise requested by the applying utility in its application, a statement that the adopting utility is adopting as its own all rates, rules, terms, conditions, agreements, concurrences, instruments, and all other provisions that have been filed or adopted by the previous utility.

3105. Securities and Liens.

- (a) Subject to the exception contained in paragraph (h) of this rule, a utility which either derives more than five percent of its consolidated gross revenues in Colorado as a public utility or derives a lesser percentage if its revenues are earned by supplying an amount of energy which equals five percent or more of Colorado's consumption shall file an application for Commission approval of any proposal to issue or to assume any security or to create a lien.
- (b) An application for the issuance or assumption of securities with a maturity of 12 months or more or to create a lien shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:
 - (I) All information required in rules 3002(b) and 3002(c).
 - (II) A copy of the resolution of the applying utility's board of directors approving the issuance, renewal, extension, or assumption of the securities or to create a lien, together with, as applicable and available, copies of the proposed indenture requirements, the mortgage note, the amendment to the loan contract, and the contract for sale of securities or creation of a lien.
 - (III) A statement describing each short-term and long-term indebtedness outstanding on the date of the most recent balance sheet.
 - (IV) A statement describing the classes and amounts of capital stock authorized by the articles of incorporation and the amount by each class of capital stock outstanding on the date of the most recent balance sheet.
 - (V) A statement of capital structure showing common equity, long-term debt, preferred stock, if any, and pro forma capital structure on the date of the most recent balance sheet giving effect to the issuance of the proposed securities. Debt and equity percentages to total capitalization, actual and pro forma, shall be shown.
 - (VI) A statement of the amount and rate of dividends declared and paid, or the amount and year of capital credits assigned and capital credits refunded, during the previous four calendar years including the present year to the date of the most recent balance sheet.
 - (VII) A statement describing the type and amount of securities to be issued; the anticipated interest rate or dividend rate; the redemption or sinking fund provisions, if any; and, within 10 days of their filing with the Securities and Exchange Commission, a copy of the registration statement, related forms, and preliminary prospectus filed with the Securities and Exchange Commission relating to the proposed issuance.
 - (VIII) A statement of proposed uses, including construction, to which the funds will be or have been applied and a concise statement of the need for the funds.
 - (IX) A statement of the estimated cost of financing.
- (c) For applications for the creation of a lien on the applying utility's property situated within the State of Colorado where the creation of the lien is not related to the issuance or assumption of a

security, the application shall also include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:

- (I) A description of the property which will be subject to the lien.
 - (II) The amount of the lien.
 - (III) The proposed use of the funds to be received from the lien.
 - (IV) The estimated cost for the creation of the lien.
 - (V) The anticipated duration of the lien.
 - (VI) The anticipated release date of the lien.
 - (VIII) The retirement payment plan to release the lien.
 - (IX) A statement describing how the applying utility will ensure that neither the creation of the lien nor the use of the proceeds will violate § 40-3-114, C.R.S.
 - (X) A statement that, for the duration of the lien, the applying utility will advise the Commission within ten days of any bankruptcy, foreclosure, or liquidation proceeding.
 - (XI) A statement that the applying utility will advise the Commission within ten days of any deviation from its lien retirement payment plan.
- (d) The Commission shall publish notice of the application, which shall set a ten-day intervention period and a hearing date.
- (e) Within three days after the filing of an application to issue or to assume a security, the applying utility shall publish notice of the filing of the application in a newspaper of general circulation. The notice shall contain the following information:
- (I) The name and address of the applying utility.
 - (II) A statement of the purpose of the application, including a statement of the effect the application would have upon existing customers if granted.
 - (III) A statement that any person may intervene in the application proceeding by complying with the applicable rule of the Commission's Rules Regulating Practice and Procedure.
- (f) The applying utility shall file with the Commission a copy of the published notice and an affidavit of publication as soon as possible after the filing of the application. The Commission shall not grant the application without a filed copy of the notice and the affidavit of publication.
- (g) The Commission shall give priority to an application made pursuant to this rule and shall grant or deny the application within 30 days after filing, unless the Commission, for good cause shown, enters an order granting an extension and stating fully the facts necessitating the extension. The

Commission shall approve or disapprove an application made pursuant to this rule by written order.

- (h) Pursuant to § 40-1-104, C.R.S., a utility may issue, renew, extend or assume liability on securities, other than stocks, with a maturity date of not more than 12 months after the date of issuance, whether secured or unsecured, without application to or order of the Commission provided that no such securities so issued shall be refunded, in whole or in part, by any issue of securities having a maturity of more than 12 months except on application to and approval of the Commission.
- (i) Any security requiring Commission approval, but issued or assumed without such approval, shall be void.

3106. Flexible Regulation to Provide Jurisdictional Service Without Reference to Tariffs.

- (a) A utility seeking authority to provide a jurisdictional service without reference to a tariff shall file an application pursuant to this rule. A utility cannot provide a jurisdictional service without reference to a tariff without authority from the Commission.
- (b) An application for flexible regulation to provide jurisdictional service without reference to tariffs shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:
 - (I) All information required in rules 3002(b) and 3002(c).
 - (II) The name of the customer or potential customer.
 - (III) A description of the jurisdictional service or services which the applying utility seeks to provide to a customer or a potential customer.
 - (IV) A statement describing the manner in which the applying utility will provide the jurisdictional service or services if it contracts with a customer or potential customer.
 - (V) A statement of the facts (not in conclusory form) which the applying utility believes satisfy the requirements of § 40-3-104.3(1)(a), C.R.S.
 - (VI) A statement that the applying utility has provided, or will provide when available, copies of the application and contract as required by paragraph (c) of this rule.
- (c) The contract which is the subject of the application shall be filed when available with the Commission under seal pursuant to rules 1100 – 1102 and § 40-3-104.3(1)(b), C.R.S. The applying utility shall furnish a copy of the application and, when it is available, of the contract, under seal, to the OCC. Unless the applying utility requests other treatment, the Commission and the OCC shall treat the contract as confidential. If the Commission grants a protective order preserving the confidentiality of the contents of an application, then the applying utility shall also furnish a non-confidential copy of the application without the contract to any utility then providing service to the customer or potential customer.

- (d) The direct testimony and exhibits to be offered at hearing shall accompany the application unless the applying utility believes that the application will be uncontested and unopposed. If an exhibit is large or cumbersome, the applying utility shall file the exhibit with the Commission; shall provide, for the benefit of the intervenors, the title of the exhibit and a summary of the information contained in the exhibit; and shall state the location (other than the Commission) at which parties may inspect the exhibit.
- (e) Prefiled testimony or exhibits shall not be modified once filed unless the modification is to correct typographical errors or misstatements of fact or unless all parties to the proceeding agree to the modification. In the event a substantive modification is made without the agreement of all parties, the Commission may consider the effect of the substantive modification as a basis for a motion to continue in order to allow the Staff or any other party a reasonable opportunity to investigate and, if necessary, to address the modification.
- (f) The Commission shall provide notice of the application. Any person desiring to intervene in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule shall move to do so within five days of the date the Commission provides notice.
- (g) Within five days of receiving written notice of an intervention in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule, the applying utility shall hand-deliver or otherwise provide to the intervenor a non-confidential copy of the application and the applying utility's prefiled testimony and exhibits.
- (h) Unless the Commission orders otherwise, the applying utility shall publish notice of the application in a newspaper of general circulation within three days of the filing of the application.
- (i) The notice provided by the applying utility shall contain the following information:
 - (I) The name and address of the applying utility.
 - (II) A statement that the applying utility is seeking an order from the Commission authorizing the applying utility to provide jurisdictional service under contract without reference to its tariffs.
 - (III) The name of the customer(s) or potential customer(s) involved.
 - (IV) A statement that the identified customer(s) or potential customer(s) may have the ability to provide its/their own service or may have competitive alternatives available to it/them.
 - (V) A general description of the jurisdictional services to be provided.
 - (VI) A statement of where affected customers may call to obtain information concerning the application.
 - (VII) A statement that anyone may file a written objection to the application but that the mere filing of a written objection will not permit participation as a party in any proceeding before the Commission.

- (VIII) A statement that anyone desiring to participate as a party must file a petition to intervene within five days from the date of Commission notice of the application and that the intervention must comport with the Commission's Rules Regulating Practice and Procedure.
- (j) Within three days of providing notice, the applying utility shall file with the Commission an affidavit showing proof of publication of notice.
- (k) On a case-by-case basis, the Commission may require the applying utility to provide additional information.
- (l) Should an application be filed which the Commission determines is not complete, the Commission or Staff shall notify the applying utility within seven days from the date the application is filed of the need for additional information. The applying utility may then supplement the application so that it is complete. Once the application is complete, the Commission will process the application, with all applicable timelines running from the date the application is completed.
- (m) The Commission shall issue an order approving or disapproving the application within the time permitted under § 40-3-104.3(1)(b), C.R.S.
- (n) At the time of any proceeding in which a utility's overall rate levels are determined, the Commission shall require the utility to file a fully distributed cost method which segregates investments, revenues, and expenses associated with jurisdictional utility service provided pursuant to contract from other regulated utility operations in order to ensure that jurisdictional utility service provided pursuant to contract is not subsidized by revenues from other regulated utility operations. If revenues from a service provided by a utility pursuant to contract are less than the cost of service for that service, the rates for other regulated utility operations shall not be increased to recover the difference.
- (o) The applying utility shall provide final contract or other description of the price and terms of service as specified in § 40-3-104.3(1)(e), C.R.S.

3107. Voluntary Air Quality Improvement Programs pursuant to § 40-3.2-102, C.R.S.

- (a) A utility seeking authority for cost recovery of a voluntary air quality improvement program shall file an application pursuant to this rule. The utility cannot recover the cost of a voluntary air quality improvement program without authority from the Commission.
- (b) An application for cost recovery of a voluntary air quality improvement program shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:
 - (I) All information required in rules 3002(b) and 3002(c).
 - (II) A copy of the voluntary agreement entered into pursuant § 40-3.2-102(1), C.R.S.

- (III) An analysis demonstrating that the proposed cost recovery mechanism complies with, and does not exceed, the rate impact cap, the total cost cap, and the recovery period limit established in § 40-3.2-102(3), C.R.S.
- (IV) A written acknowledgment that any revenues the applying utility receives from transferring, selling, banking, or otherwise using allowances under title IV of the federal Clean Air Act shall be credited to the applying utility's customers to offset air quality improvement costs if such revenues are a result of a voluntary agreement entered into under part 12 of article 7 of title 25 C.R.S., as required by § 40-3.2-102(4), C.R.S.
- (V) A statement as to whether the applying utility's generating capacity will increase under the voluntary agreement for air quality improvement.
- (VI) A statement as to whether, pursuant to § 40-3.2-102(7), C.R.S., the applying utility intends to seek recovery of a portion of the air quality improvement costs from its wholesale customers and, if it does so intend, whether the applying utility intends to credit its retail customers for air quality improvement costs recovered from wholesale customers.

3108. Tariffs and Contracts.

- (a) A utility shall keep on file with the Commission the following documents pertaining to retail electric service: its current Colorado tariffs, contracts, privileges, contract forms, and electric service agreements. These documents, unless filed under seal shall be available for public inspection at the Commission and at the principal place of business of the utility.
- (b) Tariffs shall plainly show all terms, conditions, rates, tolls, rentals, charges, and classifications collected or enforced, or to be collected and enforced, with respect to regulated services and products. A utility's tariffs shall include at least the following:
 - (I) Information regarding the utility's voltages, pursuant to rule 3202.
 - (II) Information regarding the utility's line extension policies, procedures, and conditions, pursuant to rule 3210.
 - (III) Information regarding the utility's meter testing equipment and facilities, scheduled meter testing, meter testing records, fees for meter testing upon request, and meter reading, pursuant to rules 3303, 3304, 3305, 3306, and 3309.
 - (IV) Information regarding the utility's benefit of service transfer policies, pursuant to rule 3401(c).
 - (V) Information regarding the utility's customer deposit policy, pursuant to rule 3403.
 - (VI) Information regarding the utility's installment payment plans and other plans, pursuant to rule 3404.
 - (VII) Information regarding the utility's collection fees or miscellaneous service charges, pursuant to rules 3404(c)(VI) and (VIII).

- (VIII) Information regarding the utility's after-hour restoration fees, pursuant to rule 3409(b).
- (IX) Information regarding the utility's avoided costs, pursuant to rule 3902(b).
- (X) Rules, regulations, and policies covering the relations between the customer and the utility.

3109. New or Changed Tariffs.

- (a) A utility shall file with the Commission any new or changed tariffs. No new or changed tariff shall be effective unless it is filed with the Commission and either is allowed to go into effect by operation of law or is approved by the Commission.
- (b) A utility shall use one of the following processes to seek to add a new tariff or to change an existing tariff:
 - (I) The utility may file the proposed tariff, including the proposed effective date, accompanied by an advice letter. The utility shall provide notice in accordance with rule 1206. If the Commission does not suspend the proposed tariff in accordance with rule 1305 prior to the tariff's proposed effective date, the proposed tariff shall take effect on the proposed effective date.
 - (II) The utility may file an application to implement a proposed tariff on less than 30-days' notice, accompanied by the proposed tariff, including the proposed effective date. The utility shall provide notice in accordance with rule 1206. The application shall include the information required in rules 3002(b) and 3002(c); shall explain the details of the proposed tariff, including financial data if applicable; shall state the facts which are the basis for the request that the proposed tariff become effective on less than 30-days' notice; and shall note any prior Commission action, in any proceeding, pertaining to the present or proposed tariff.
 - (III) Unless the Commission orders otherwise, a utility shall be permitted to file new tariffs complying with an order of the Commission or updating adjustment clauses previously approved by the Commission on not less than one days notice. No additional notice beyond the tariff filing itself shall be required.
- (c) Each tariff sheet which is not an original shall be designated "1st revised sheet No. ____ cancels original sheet No. ____," or "2nd revised sheet No. ____ cancels 1st revised sheet No. ____," as appropriate. Each sheet shall direct attention to the changes by the use of symbols in the right margin (for example, "I" for increase, "D" for decrease, "C" for change in text, and "N" for new text). On a contents or index page the utility shall show the meaning of the symbols used by it to point out changes contained in its revised tariff filings. If a tariff sheet is issued under a specific authority or Commission decision, the tariff sheet shall show the specific authority or Commission decision number in the space provided at the foot of the sheet.
- (d) The Commission may reject any tariff that is not in the form, or does not contain the information, required by statute, by rule, or by Commission order and decision. Any tariff rejected by the Commission shall be void and shall not be used.

3110. Advice Letters.

Each proposed tariff shall be accompanied by a serially-numbered advice letter. The letter shall list all sheets included in the filing by number and shall show the sheets being cancelled, if any. The advice letter shall state the purpose of the filing; shall identify each change being proposed; shall state the amounts, if any, by which the utility's revenues will be affected; shall summarize clearly the extent to which customers will be affected; and shall provide information demonstrating that the proposed tariff is just and reasonable.

3111. – 3199. [Reserved]**FACILITIES****3200. Construction, Installation, Maintenance, and Operation.**

- (a) The plant, equipment, and facilities of a utility shall be constructed, installed, inspected, maintained, and operated in accordance with accepted engineering practice in the electric industry to assure continuity of service, uniformity in the quality of service, and the safety of persons and property.
- (b) For all electric plant construction or installation, the minimum standard of accepted engineering practice is the edition of the National Electrical Safety Code in effect at the time of commencing construction or installation of the electric plant.
- (c) Any utility plant that was constructed or installed, and that is maintained and operated, in accordance with the National Electrical Safety Code in effect at the time of its construction or installation shall be presumed to be in compliance with accepted engineering practice in the electric industry and with the provisions of this rule.

3201. Production Plant Instruments.

Each electric utility shall install such indicating watt meters, watt-hour meters, or other instruments as may be necessary to obtain a daily record of the load and a monthly record of the output of its production plants. Each utility purchasing electrical energy shall install such instruments or meters as may be necessary to furnish full information as to the monthly purchases.

3202. Standard Voltage and Frequency; Applications for Variance.

- (a) A utility must make every reasonable effort consistent with good engineering practices to maintain a constant frequency and constant voltage on its facilities at all times.
- (b) A utility shall periodically measure and record service voltages maintained at the utility's main service terminals as installed for individual customers or groups of customers. Those service voltages shall be practically constant as follows:
 - (l) For service rendered under a lighting contract or primarily for lighting purposes, the voltage shall be maintained within five percent above or below the standard stated in the utility's tariff.

- (II) For service rendered under a power contract or primarily for power purposes, the voltage shall be maintained within ten percent above or below the standard stated in the utility's tariff.
- (c) The following shall not be considered a violation of paragraph (b) of this rule:
 - (I) A temporary variation in voltage in excess of those specified if caused by the operation of power apparatus on a customer's premises which necessarily require large starting currents, provided that only the customer's premises are affected. If other customers are affected, the utility shall work with the customer causing the variation to resolve the voltage fluctuation/violation problem or problems.
 - (II) A temporary variation in voltage in excess of those specified if caused by the action of the elements.
 - (III) A temporary variation in voltage in excess of those specified if caused by infrequent, unavoidable, and short-duration fluctuations due to necessary station or line operations.
- (d) If a utility seeks to operate at a greater variation in voltages than permitted by paragraph (b) of this rule, the utility shall file an application for a variance. An application for variance shall include:
 - (I) All information required in rules 3002(b) and 3002(c).
 - (II) Delineation of the geographic boundaries of the service territory for which the variance is sought.
 - (III) A statement of the facts (not in conclusory form) which supports the need for the requested variance.
 - (IV) A demonstration that the applying utility proposes to provide the best voltage regulation practicable under the circumstances.
- (e) The Commission may allow a greater variation of voltage when:
 - (I) Service is furnished directly from a transmission line.
 - (II) Service is furnished in a limited or extended area where customers are widely scattered and the business done within that area does not justify close voltage regulation (such as individual customers or small groups of customers whose service from a transmission line is incidental).
- (f) Each utility's tariff shall include a description of test methods, equipment, and frequency of testing used to determine the voltage of electric service furnished.
- (g) Each utility's tariff shall include a description of standard average voltage, or voltages, and frequency, or frequencies, as may be required by:
 - (I) The utility's distribution system,

- (II) The utility's entire system, or
- (III) Each of the several districts into which the utility's system may be divided.

3203. Interruptions of Service.

- (a) Each utility shall keep a record of every service interruption (including, without limitation, forced outages caused by events outside of the utility's control, scheduled outages, or sustained outages) which occurs on its entire system or on a major division of its system. The record shall include at least a statement of the time, the duration, and the cause of any service interruption. .
- (b) The records of service interruptions and a statement of the utility's operating schedules shall be open at all times to the inspection of the duly authorized representatives of the Commission. The utility shall retain these records for five years.
- (c) As used in this rule, "service interruption" means a loss of service consistent with IEEE Standard Number 1366, Guide for Electric Power Distribution Reliability Indices.

3204. Incidents.

- (a) In compliance with the policies adopted from time to time by the Commission to implement this rule and within two hours (120 minutes) of learning of the incident, each utility shall inform the Commission of an incident which occurs in connection with the operation of its property, facilities, or service and which results in death, serious injury, or significant property damage.
- (b) Within 30 calendar days of the incident, the utility shall submit a written report to the Director of the Commission. The report shall contain at least the following information:
 - (I) Date, time, place, and location of the incident.
 - (II) Type of incident.
 - (III) Names of all persons involved.
 - (IV) Nature and extent of injury and damage.
- (c) If the utility conducts an internal investigation of an incident referred to in paragraph (a) above, the utility shall make its report available to the Commission upon request by the Commission. The utility may provide paragraphs (b)(III) and (b)(IV) of this report on a confidential basis under seal.

3205. Construction or Expansion of Generating Capacity.

- (a) No utility may commence new construction or an expansion of generation facilities or projects until either the Commission notifies the utility that such facilities or projects do not require a certificate of public convenience and necessity or the Commission issues a certificate of public convenience and necessity for the facility or project. Rural electric cooperatives do not need a certificate of public convenience and necessity for new construction or an expansion of

generation facilities provided that such construction or expansion is contained entirely within the cooperative's certificated area.

- (b) The following shall be deemed to occur in the ordinary course of business and shall not require a certificate of public convenience and necessity:
 - (I) New construction or expansion of existing generation which will result in an increase in generating capacity of less than ten megawatts.
 - (II) A generating plant remodel, or installation of any equipment or building space, required for pollution control systems.
- (c) For each new construction or expansion of existing generation that will result in an increase in generating capacity of ten megawatts or more, the electric utility shall submit to the Commission, no later than April 30 of each year, a filing for a determination of which of the utility's proposed new construction or expansions for the next three calendar years, commencing with the year following the filing, are necessary in the ordinary course of business and which require a certificate of public convenience and necessity prior to construction. For each project, the filing shall contain the following:
 - (I) The name, proposed location, and function or purpose of the project.
 - (II) The estimated cost of the project and the manner in which it is expected to be financed.
 - (III) The projected date for the start of construction, the estimated date of completion, and the estimated date of commencement of operation.
- (d) The Commission will give notice of each filing made pursuant to paragraph (c) of this rule to all those who it believes may be interested. Any interested person may file comments regarding the projects by May 15.
- (e) The Staff shall review the filing and any comments received and shall make recommendations in accordance with the following schedule:
 - (I) For any new construction or expansion project which is scheduled to begin in the year of the filing or the next calendar year and which will result in an increase in generating capacity of ten megawatts or more, the Staff shall make its recommendations by May 31 of the year in which the filing is made.
 - (II) For any new construction or expansion project which is scheduled to begin in the second or third calendar year following the year in which the filing is made and which will result in an increase in generating capacity of ten megawatts or more, the Staff shall make its recommendations by August 31 of the year in which the filing is made.
- (f) The Commission shall issue its decision in accordance with the following schedule:
 - (I) For any new construction or expansion project which is scheduled to begin in the calendar year of the filing or in the next calendar year and which will result in an increase in generating capacity of ten megawatts or more, the decision designating each

generation project that requires a certificate of public convenience and necessity will be issued by June 30 of the year in which the filing is made.

- (II) For any new construction or expansion project which is scheduled to begin in the second or third calendar year following the year in which the filing is made and which will result in an increase in generating capacity of ten megawatts or more, the decision designating each generation project that requires a certificate of public convenience and necessity will be issued by October 31 of the year in which the filing is made.

3206. Construction or Extension of Transmission Facilities.

- (a) No utility and no cooperative electric association which has voted to exempt itself pursuant to § 40-9.5-103, C.R.S., may commence new construction, or extension of transmission facilities or projects until either the Commission notifies the utility that such facilities or projects do not require a certificate of public convenience and necessity or the Commission issues a certificate of public convenience and necessity. Rural electric cooperatives which have elected to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-103, C.R.S., do not need a certificate of public convenience and necessity for new construction or extension of transmission facilities or projects when such construction or expansion is contained entirely within the cooperative's certificated area.
- (b) Certain modifications to transmission facilities that were not part of the construction design authorized through a previous Commission determination shall be reviewed by the Commission for determination of whether a certificate of public convenience and necessity is needed for the proposed modification or whether the proposed modification is in the ordinary course of business. Modifications requiring this Commission determination shall be limited to the following:
 - (I) replacement of the existing conductor with another having a higher ampacity or with multiple conductors, with continued operation at the existing voltage;
 - (II) modification of the transmission facility so that it will be operated at a higher voltage, with or without conductor replacement; and
 - (III) extensions of existing substations that require acquisition of additional land for expansion of the substation yard.

All other modifications to existing transmission facilities shall not require a certificate of public convenience and necessity and shall be deemed to be in the ordinary course of business.

- (c) No later than April 30 of each year, each electric utility and each cooperative electric association which has voted to exempt itself pursuant to § 40-9.5-103, C.R.S., shall submit to the Commission a filing for a determination of which of the utility's proposed new construction or extension of transmission facilities for the next three calendar years, commencing with the year following the filing, are necessary in the ordinary course of business and which require a certificate of public convenience and necessity prior to construction. The filing shall contain a reference to all such proposed new construction or extensions, regardless of whether the utility or cooperative electric association has referenced such new construction or extensions in prior annual filings. For each project, the filing shall contain the following:
 - (I) The name, proposed location, and function or purpose of the project, including:

- (A) If the project is a substation or related facilities: the voltage level and the MVA rating.
 - (B) If the project is a transmission line: the voltage, the length in miles, the substation termination points.
- (II) The estimated cost of the project and the manner in which it is expected to be financed.
- (III) The projected date for the start of construction, the estimated date of completion, and the estimated date of commencement of operation of each project.
- (IV) For new construction or extensions that have been referenced in prior annual filings, an update of the status of, and any changes to, such new construction or extensions.
- (d) In addition to the information provided in paragraph (c) of this rule, the filing shall describe the utility's actions and techniques relating to prudent avoidance with respect to planning, siting, construction, and operation of the proposed construction or extension. As used in this paragraph, "prudent avoidance" means the striking of a reasonable balance between the potential health effects of exposure to magnetic fields and the cost and impacts of mitigation of such exposure, by taking steps to reduce the exposure at reasonable or modest cost. The steps and techniques may include, without limitation, the following:
 - (I) Design alternatives considering the spatial arrangement of phasing of conductors.
 - (II) Routing lines to limit exposures to areas of concentrated population and group facilities such as schools and hospitals.
 - (III) Installing higher structures.
 - (IV) Widening right of way corridors.
 - (V) Burying lines.
- (e) In addition to the information provided in paragraph (c) of this rule, the applying utility shall describe its actions and techniques relating to cost-effective noise mitigation with respect to the planning, siting, construction, and operation of the proposed transmission construction or extension. If the transmission facility has reached the design stage where noise levels can be calculated, the applying utility shall provide computer studies which show the potential noise levels expressed in db(A) and measured at the edge of the transmission line right-of-way. These computer studies shall be the output of utility standard programs, such as EPRI's EMF Workstation 2.51 ENVIRO Program -- Bonneville Power Administration model. The steps and techniques may include, without limitation, the following:
 - (I) Bundled conductors.
 - (II) Larger conductors.
 - (III) Design alternatives considering the spatial arrangement of phasing of conductors.

- (IV) Corona-free attachment hardware.
 - (V) Conductor quality.
 - (VI) Handling and packaging of conductor.
 - (VII) Construction techniques.
 - (VIII) Line tension.
- (f) The Commission will give notice of each filing made pursuant to this rule to all those who it believes may be interested. Any interested person may file comments regarding the projects by May 15.
- (g) The Staff shall review the filing and any comments received and shall make recommendations according to the following schedule:
- (I) For any new construction or extension which is scheduled to begin in the calendar year of the filing or in the next calendar year, the Staff shall make its recommendations by May 31 of the year in which the filing is made.
 - (II) For any new construction or extension which is scheduled to begin in the second or third calendar year following the year in which the filing is made, the staff shall make its recommendations by August 31 of the year in which the filing is made.
- (h) The Commission shall issue its decision in accordance with the following schedule:
- (I) For any new construction or extension of transmission facilities or projects which is scheduled to begin in the calendar year of the filing or in the next calendar year, the decision designating each transmission facility that requires a certificate of public convenience and necessity will be issued by June 30 of the year in which the filing is made.
 - (II) For any new construction or extension of transmission facilities which is scheduled to begin in the second or third calendar year following the year in which the filing is made, the decision designating each transmission facility that requires a certificate of public convenience and necessity will be issued by October 31 of the year in which the filing is made.
- (i) The utility shall install and maintain service connections from transmission extensions consistent with conditions contained in the utility's tariff.
- (j) In addition to the list of new construction or extension of transmission facilities, each utility shall provide by April 30 of each year a list of projects built during the past calendar year. These projects, considered as being done in the normal course of business, shall include the following:
- (I) New and /or the replacement of transformers, breakers, or capacitor banks with larger transformers, breakers or capacitor banks.

- (II) The raising and/or strategic placement of transmission structures in order to raise the conductor, thereby increasing clearance, permitting more current flow and increasing the MVA rating.
- (III) The declaration of a higher rating for a line after an engineering and physical inspection such that existing line clearances are sufficient to allow more current flow, thereby increasing the MVA rating.

3207. Construction or Expansion of Distribution Facilities.

- (a) Expansion of distribution facilities, as authorized in § 40-5-101, C.R.S., is deemed to occur in the ordinary course of business and shall not require a certificate of public convenience and necessity.
- (b) The utility shall install and maintain service connections from distribution extensions consistent with conditions contained in the utility's tariff.
- (c) When a customer or potential customer requests a cost estimate of a distribution line extension, the utility shall provide a photovoltaic system cost comparison, if the following conditions are met:
 - (I) The customer or potential customer provides the utility with load data (estimated monthly kilowatt-hour usage) as requested by the utility to conduct the comparison.
 - (II) The customer or potential customer's peak demand is estimated to be less than 25 KW.
- (d) In performing a photovoltaic system cost comparison analysis, the utility will consider line extension distance, overhead/underground construction, terrain, other variable construction costs, and the probability of additions to the line extension within the life of the open extension period.
- (e) If the customer or potential customer has a ratio of estimated monthly kilowatt-hour usage divided by line extension mileage that is less than or equal to 1,000 (i.e., kWh/Mileage is $\leq 1,000$), the utility shall provide the photovoltaic system cost comparison at no cost to the customer or potential customer. If the ratio is greater than 1,000, the customer or potential customer shall bear the cost of the comparison, if the cost comparison is requested by the customer or potential customer.

3208. Poles.

- (a) In the case of two or more utilities jointly owning or using a pole or pole line structure, each of the utilities shall mark each pole or structure with the initials of its name, abbreviation of its name, corporate symbol, or other distinguishing mark so that the ownership of such structure may be readily and definitely determined.
- (b) A utility shall mark each wood pole, post, tower, or other structure used for the support or attachment of electrical conductors, guys, or lamps, with dating nails or similar devices indicating the year in which the structure was installed.

- (c) In accordance with prudent utility practices, a utility shall inspect, and shall timely repair or replace, each of the following which it owns or uses: poles, posts, towers, or other structures used for the support or attachment of electrical conductors, guys, or lamps.
- (d) The requirements of this rule shall apply to all existing and future erected structures and to all changes in ownership.

3209. Service Connections.

Service connections to customer premises or property involving overhead or underground equipment shall be installed and maintained consistent with the conditions stated in the utility's tariff. In special cases involving either overhead or underground service connections and as necessary, the Commission will prescribe the proper charge.

3210. Line Extension.

- (a) Each utility shall have tariffs which set out its line extension policies, procedures, and conditions.
- (b) Specific tariff provisions for making overhead or underground service connections, for transmission line extensions, and for distribution line extensions shall include:
 - (I) Service connections and distribution line extensions by customer class and the appropriate terms and conditions under which those connections and extensions will be made.
 - (II) Provisions requiring the utility to provide to a customer or to a potential customer, upon request, service connection information necessary to allow the customer's or potential customer's facilities to be connected to the utility's system.
 - (III) Provisions requiring the utility to exercise due diligence in providing the customer or potential customer with an estimate of the anticipated cost of a connection or extension.
 - (IV) Provisions addressing steps to ameliorate the rate and service impact upon existing customers, including equitably allowing future customers to share costs incurred by the initial or existing customers served by a connection or extension (as, for example, by including a refund of customer connection or extension payments when appropriate).
 - (V) A description of specific customer categories (such as permanent, indeterminate, and temporary) within each customer class.
- (c) Upon request by a customer or a potential customer, the utility shall conduct a comparison of photovoltaic energy to any proposed distribution line extension if a customer or potential customer provides the utility with load data (estimated monthly kWh usage) requested by the utility to conduct the comparison and if the customer's or potential customer's peak demand is estimated to be less than 25 KW. In performing the comparison analysis, the utility will consider line extension distance, overhead/underground construction, terrain, other variable construction costs, and the probability of additions to the line extension during the life of the open extension period. If the customer has a ratio of estimated monthly kWh usage divided by line extension mileage that is less than or equal to 1,000 (i.e., kWh/Mileage is $\leq 1,000$), the utility shall provide

the photovoltaic system cost comparison at no cost to the customer or potential customer. If the ratio is greater than 1,000, the customer or potential customer shall bear the cost of the comparison, if the cost comparison is requested by the customer or potential customer.

3211. – 3249. [Reserved]

MAJOR EVENTS REPORTING

The purpose of this section is to provide timely information to the Commission regarding major events on electric systems that result in loss of electric service to its customers. The data gathered pursuant to this section will be for information purposes in order to provide the Commission with an active and current record as to the reliability of the electric systems in Colorado. The intent of these rules is to merely provide the Commission with information which is already compiled by the utilities following a major event on their system.

3250. Definitions.

The following definition applies to rules 3250-3253, unless a specific statute or rule provides otherwise.

In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply. A "Major Event" means an event as defined in and consistent with IEEE Standard Number 1366-2003, Guide for Electric Power Distribution Reliability Indices.

3251. Notification to Commission.

Each utility shall notify the Commission of a major event as soon as possible, but in any event no later than the first business day following the major event.. The notification of the event should be by e-mail sent to the Chief Engineer of the Fixed Utilities Section of the Commission at the following e-mail address: PUC@dora.state.co.us.

3252. Report.

- (a) Within 15 calendar days after the end of a major event, a utility shall submit a written report to the Director of the Commission.
- (b) At a minimum, the report shall include the following:
 - (I) The date and time when the major event began; the date and time when the utility's control center began treating the situation as a major event; and the date and time when the utility classified the major event as closed.
 - (II) The total number of customers out-of-service over the course of the major event and the general (by city or district level) area in which the major event occurred.
 - (III) The total number of affected locations by facility classification.
 - (IV) The date and time at which any mutual aid and non-utility contractor crews were requested; the date and time when each such crew arrived for duty; the date and time when each such crew was released from duty; and the non-utility contractor response(s) to the request(s) for assistance.

- (V) A timeline profile on the number of utility line crews, mutual aid crews, and non-utility contractor line and tree crews working on restoration activities during the major event.
- (VI) Identification of the cause(s) of the major event and of the factors which contributed to the major event.
- (VII) A listing of each new or existing policy, procedure, and guideline which the utility will implement or has implemented in order to prevent a similar major event or recurrence of the major event in the future.
- (VIII) An affidavit of an officer of the utility, which affidavit verifies the information in the report.

3253. Supplemental or Additional Major Event Reporting.

- (a) With respect to generation and transmission disturbances, utilities shall provide to Commission Staff, on a confidential basis, copies of any reports required by the Western Electricity Coordinating Council.
- (b) With respect to generation and transmission disturbances, utilities shall provide to Commission Staff, on a confidential basis, copies of any Emergency Incident and Disturbance Reports filed with the Energy Information Administration of the United States Department of Energy on significant transmission or generation disturbances.
- (c) At such time and in such form as the Commission may require, each utility shall furnish to the Commission a report in which the utility specifically answers all questions propounded regarding a major event or events and provides such other information relevant to the major event and the restoration of service as the Commission may request. The Commission may require utilities to provide these supplemental or additional reports at regular intervals, to be determined by the Commission, and on a form approved by the Commission. Periodic or special reports concerning any matter about which the Commission is concerned relative to the occurrence of one or more major events shall be furnished in a manner determined by the Commission and on a form approved by the Commission.

3254. – 3299. [Reserved]

METERS

3300. Service Meters and Related Equipment.

- (a) All meters used in connection with electric metered service for billing purposes shall be furnished, installed, and maintained by the utility.
- (b) Any equipment, devices, or facilities (including, without limitation, service meters) furnished by the utility and which the utility maintains and renews shall remain the property of the utility and may be removed by it at any time after discontinuance of service.
- (c) Each electric service meter shall indicate clearly the kWh and units of demand, where applicable, for which the customer is charged. In cases in which the register and/or chart reading must be multiplied by a constant or factor to obtain the units consumed, the factor, factors, or constant

shall be clearly marked either on the register or face of the meter or in permanently attached and clearly visible documentation at the meter location. In cases in which the metering installation is of such a complex nature that disclosure of the constant or factor used is unsuitable to inform the customer of quantities of utility service being consumed, the utility shall attach at the meter location instructions on how the customer can receive such information from the utility.

3301. Location of Service Meters.

- (a) As of the time of installation, meters shall be located in accordance with the pertinent utility tariffs and in accordance with accepted safe practice and electric utility industry standards.
- (b) As of the time of installation, meters shall be located so as to be easily accessible for reading, testing, and servicing in accordance with accepted safe practice and in accordance with electric utility industry standards.

3302. Service Meter Accuracy.

- (a) No service watt-hour meter that has an incorrect register constant, test constant, gear ratio or dial train, or that creeps shall be placed in service or allowed to remain in service without proper adjustment and correction.
- (b) No service watt-hour meter that has an error in registration of more than plus or minus two percent, either at light load or at heavy load, shall be placed in service. Whenever a meter is found to exceed these limits, it shall be adjusted or replaced.
- (c) No demand meter shall have an allowable error of more than two percent of full-scale deflection, except that the allowable error for thermal type meters may be three percent. Whenever a meter is found to exceed these limits, it shall be adjusted or replaced.
- (d) Meters used with instrument transformers or current transformers shall be adjusted or replaced so that the overall accuracy of the metering installation meets the requirements of this rule.

3303. Meter Testing Equipment and Facilities.

- (a) Unless specifically exempted by the Commission, each utility furnishing metered electric service shall provide such meter laboratory, standard meters, instruments, and other equipment and facilities as may be necessary to make the tests required by these rules. Such equipment and facilities shall be acceptable to the Commission and shall be available at all reasonable times for inspection by the Commission's authorized representatives.
- (b) Each utility shall make such tests as are prescribed under these rules with such frequency, in such manner, and at such places as may be approved by this Commission. Each utility shall file an application for approval of its testing practices. The application shall include:
 - (I) All information required by rules 3002(b) and 3002(c).

- (II) A description of the test methods employed and the frequency of tests or observations for determining voltage of electric service furnished.
 - (III) A description of meter testing equipment, including methods employed to ascertain and maintain accuracy of all testing equipment.
 - (IV) Rules covering testing and adjustment of service meters when installed and periodic tests after installation.
 - (V) Supporting information and justification for the items listed in subparagraphs (II) through (IV) of this paragraph.
- (c) Revisions to any portion of testing practices approved pursuant to the procedure in paragraph (b) of this rule shall be accomplished by the filing and approval of a new application.
 - (d) Each utility furnishing metered electric service shall provide such portable indicating electrical testing instruments or portable watt-hour meters of suitable range and type for testing switchboard instruments, recording volt-meters, service watt-hour meters, and other electrical instruments in use, as may be deemed necessary and satisfactory by the Commission.
 - (e) Rotating standards that are used by the utility in testing service meters shall be tested for accuracy by using reference standards. If the reference standards used by the utility are service type watt-hour meters, those watt-hour meters must be permanently mounted in the utility's laboratory and may be used for no other purpose than testing rotating standards.
 - (f) Reference standards shall be submitted at least once each year to a laboratory of recognized standing, for the purpose of testing and adjustment. A utility that maintains its own standardizing laboratory shall be permitted to test and certify its own reference standards, provided the instruments and methods used are acceptable to the Commission.
 - (g) When in use, commutator-type rotating standards shall be compared with the reference standards in accordance with the manufacturer's recommended frequency. When in use, induction-type rotating standards shall be compared with the reference standards in accordance with the manufacturer's recommended frequency. If any working rotating standard tests within plus or minus one percent error at any load at which the standard will be used, the standard may be adjusted by comparison with the utility's reference standards. However, if any working rotating standard tests in error of more than plus or minus one percent, that standard shall be tested, adjusted, and certified in a standardizing laboratory of recognized standing. If a utility is exempted as provided in paragraph (a) of this rule, it shall have its working rotating standards tested by a standardizing laboratory of recognized standing at least once a year. Each rotating standard shall at all times be accompanied by a certificate or calibrating card signed by the standardizing laboratory, giving the date when it was last certified and adjusted.
 - (h) When in use, all electrical meter testing equipment shall have their calibration checked either annually or more frequently if specified by the manufacturer. For all instruments requiring an as found/as left date sheet, calibration certifications shall be kept on-site for a period of seven years or until the instruments are recertified by a laboratory of recognized standing, whichever is later. All instruments shall have a tag affixed stating the date calibrated and the date the instrument is due for recertification. If an instrument is found to be out of the manufacturer's specifications, the

instrument shall be calibrated and certified to the manufacturer's specifications by a laboratory of recognized standing. Upon request from any person, a copy of the certification letter and date sheet shall be provided for the instrument in question.

- (i) A utility shall keep records of certification and calibrations for all testing equipment required by this rule for the life of the equipment.
- (j) In its tariff, a utility shall include a description of its meter testing equipment and of the methods employed to ascertain and to maintain accuracy of all testing equipment.
- (k) For those paragraphs of this rule which require a utility to maintain facilities and equipment, a utility may meet those requirements by having the facilities and equipment readily available (as, for example and without limitation, by contracting with a testing facility). A utility which uses this paragraph of the rule is responsible for its compliance with the provisions of this entire rule.
- (l) For those paragraphs of this rule which require a utility to test or to maintain equipment, a utility may meet those requirements by having the equipment tested by a third party (as, for example and without limitation, an independent testing facility). A utility which uses this paragraph of the rule is responsible for its compliance with the provisions of this entire rule.

3304. Scheduled Meter Testing.

- (a) A utility shall test, or shall arrange for testing of, service meters in accordance with the schedule in this rule or in accordance with a sampling program approved by the Commission.
- (b) If it wishes to use a sampling program, a utility shall file an application to request approval of a sampling program. The application shall include:
 - (I) The information required by rules 3002(b) and 3002(c).
 - (II) A description of the sampling program which the utility wishes to use. This description shall include, at a minimum the following:
 - (A) The type(s) of meters subject to the sampling plan.
 - (B) The frequency of testing.
 - (C) The procedures to be used for the sampling.
 - (D) The reference standard to be used for testing.
 - (E) The accuracy of the testing and of the sampling plan.
 - (III) An explanation of the reason(s) for the requested sampling program.
 - (IV) An analysis which demonstrates that, with respect to assuring the accuracy of the service meters tested, the requested sampling program is at least as effective as the schedule in this rule.

- (c) Revisions to any portion of a sampling program approved pursuant to paragraph (b) of this rule shall be accomplished by the filing of, and Commission approval of, a new application.
- (d) Every service meter must be tested and adjusted, either before installation or no later than 60 days after installation, to ensure that it registers accurately and conforms to the requirements of rule 3302. In addition, every service meter shall be tested on a periodic basis, as follows:
 - (I) Alternating current watt-hour meters:
 - (A) Polyphase meters used with instrument transformers, every four years.
 - (B) Single-phase meters used with instrument transformers, every eight years.
 - (C) Self-contained polyphase meters, every six years.
 - (D) Self-contained single-phase meters and three wire network meters, every eight years.
 - (II) Direct current watt-hour meters:
 - (A) Up to and including 6 KW, every 42 months.
 - (B) Over 6 KW up to and including 100 KW, every 18 months.
 - (C) Over 100 KW, every 12 months.
 - (III) Var-hour meters and lagged demand meters shall be tested on the same schedule as the associated watt-hour meters in subparagraph (c)(I) or (II) of this rule. Integrated (block interval) demand meters, including demand registers and associated control devices, shall be tested on the same schedule as the associated watt-hour meters in subparagraph (c)(I) or (II) of this rule, but at least every six years.
- (e) In its tariff, each utility shall include a description of the utility's practices concerning the following:
 - (I) Testing and adjustment of service meters at installation.
 - (II) Periodic testing after installation.

3305. Meter Testing Upon Request.

- (a) Each utility furnishing metered electric service shall test the accuracy of any electric service meter upon request of a customer. The test shall be conducted free of charge if the meter has not been tested within the previous 12 months and if the customer agrees to accept the results of the test for the purposes of any dispute or informal complaint regarding the meter's accuracy; otherwise, the utility may charge a fee for performing the test. The utility shall provide a written report of the test results to the customer and shall maintain a copy on file for at least two years.
- (b) Should a customer request and receive a meter test as prescribed in Rule 3305(a) and continue to dispute the accuracy of a meter, upon written request by a customer the utility shall make the

disputed meter available for independent testing by a qualified meter testing facility of the customer's choosing. The customer is not entitled to take physical possession of the disputed meter. To be a qualified meter testing facility, the testing facility must be capable of testing the meter to meet all meter standards and requirements required by these rules.

- (c) This rule applies only when there is disagreement between the customer and the utility regarding the accuracy of the meter. If, upon completion of an independent test [as prescribed in rule 3305\(b\)](#), the disputed meter is found to be accurate within the limits of rule 3302, the customer shall bear all costs associated with conducting the test. If, upon completion of an independent test [as prescribed in rule 3305\(b\)](#), the disputed meter is found to be inaccurate beyond the limits prescribed in rule 3302, the utility shall bear all costs associated with conducting the test.
- (d) In its tariff, each utility shall include any fees associated with customer-requested meter testing conducted within 12 months of a prior test.

3306. Records of Tests and Meters.

- (a) For each meter owned or used by it, a utility shall maintain a record showing the date of purchase, the manufacturer's serial number, the record of the present location, and the date and results of the last test performed by the utility. This record shall be retained for the life of the meter plus 30 months.
- (b) Whenever a meter is tested either on request or upon complaint, the test record shall include the information necessary for identifying the meter, the reason for making the test, the reading of the meter if removed from service, the result of the test, and all data taken at the time of the test in a sufficiently complete form to permit the convenient checking of the method employed and the calculations made. This record shall be retained for at least two years.

3307. [Reserved]

3308. [Reserved]

3309. Meter Reading.

- (a) Upon a customer's request, a utility shall provide written documentation showing the date of the most recent reading of the customer's meter and the total usage expressed in kilowatt-hours or other unit of service recorded. On request, a utility supplying metered service shall explain to its customers its method of reading meters.
- (b) In its tariff, a utility shall include a clear statement describing when meters will be read by the utility and the circumstances, if any, under which the customer must read the meter and submit the data to the utility. This statement shall specify in detail the procedure that the customer must follow and shall specify any special conditions which apply only to certain classes of service.
- (c) Absent good cause, a utility shall read a meter monthly. For good cause shown, a utility shall read a meter at least once every six months.

3310. – 3399. [Reserved]

BILLING AND SERVICE

3400. Applicability.

Rules 3400 through 3410 apply to residential customers, small commercial customers and agricultural customers served pursuant to a utility's rates or tariffs. In its tariffs, a utility shall define "residential," "small commercial" and "agricultural" customers to which these rules apply. The utility may elect to apply the same or different terms and conditions of service to other customers.

3401. Billing Information and Procedures.

- (a) All bills issued to customers for metered service furnished shall show:
 - (I) The dates and meter readings beginning and ending the period during which service was rendered.
 - (II) An appropriate rate or rate code identification.
 - (III) The net amount due for regulated charges.
 - (IV) The date by which payment is due, which shall not be earlier than 15 days after the mailing or the hand-delivery of the bill.
 - (V) A distinct marking to identify an estimated bill.
 - (VI) The total amount of all payments or other credits made to the customer's account during the billing period.
 - (VII) Any past due amount. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges.
 - (VIII) The identification of, and amount due for, unregulated charges, if applicable.
 - (IX) Any transferred amount or balance from any account other than the customer's current account.
 - (X) All other essential facts upon which the bill is based, including factors and constants, as applicable.
- (b) A utility that bills for unregulated services or goods shall allocate any partial payment first to regulated charges and then to unregulated charges or non-tariffed charges and to the oldest balance due separately within each category.
- (c) A utility that transfers to a customer a balance from the account of a person other than that customer shall have in its tariffs the utility's benefit of service transfer policies and criteria. The tariffs shall contain an explanation of the process by which the utility will verify, prior to billing a customer under the benefit of service tariff, that the person to be billed in fact received the benefit of service.

- (d) A utility may transfer a prior unpaid debt to a customer's bill if the prior bill was in the name of the customer and the utility has informed the customer of the transferred amount and of the source of the unpaid debt (for example, and without limitation, the address of the premises to which service was provided and the period during which service was provided).
- (e) If it is offered in a tariff, upon request from a customer and where it is technically feasible, a utility may have the option to provide electronic billing (e-billing), in lieu of a typed or machine-printed bill, to the requesting customer. If a utility offers the option of e-billing, the following shall apply:
 - (I) The utility shall obtain the affirmative consent of a customer to accept such a method of billing in lieu of printed bills.
 - (II) The utility shall not charge a fee for billing through the e-billing option.
 - (III) The utility shall not charge a fee based on customer payment options that is different from the fee charged for the use of the same customer payment options by customers who receive printed bills.
 - (IV) A bill issued electronically shall contain the same disclosures and Commission-required information as those contained in the printed bill provided to other customers.

3402. Adjustments for Meter and Billing Errors.

- (a) A utility shall adjust customer charges for electricity incorrectly metered or billed as follows:
 - (I) When, upon any meter accuracy test, a meter is found to be running slow in excess of error tolerance levels allowed under rule 3302, the utility may charge for one-half of the weighted average error for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed six months. As used in this subparagraph, "weighted average error" means the arithmetic average of the percent error at light load and at heavy load giving the heavy load error a weight of four and the light load error a weight of one.
 - (II) When, upon any meter accuracy test, a meter is found to be running fast in excess of error tolerance levels allowed under rule 3302, the utility shall refund one-half of the weighted average error for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed two years. As used in this subparagraph, "weighted average error" means the arithmetic average of the percent error at light load and at heavy load giving the heavy load error a weight of four and the light load error a weight of one.
 - (III) When a meter does not register, registers intermittently, or partially registers for any period, the utility may estimate, using the method stated in its tariff, a charge for the electricity used based on amounts metered to the customer over a similar period in previous years. The period for which the utility charges the estimated amount shall not exceed six months.
 - (IV) In the event of under-billings not provided for in subparagraph (a)(I) or (III) of this rule (such as, but not limited to, an incorrect multiplier, an incorrect register, or a billing error),

the utility may charge for the period during which the under-billing occurred, with such period not to exceed six months.

- (V) In the event of over-billings not provided for in subparagraph (a)(II) of this rule, the utility shall refund for the period during which the over-billing occurred, with such period not to exceed two years.
- (b) The periods set out in paragraph (a) of this rule shall commence on the date on which (1) either the customer notifies the utility or the utility notifies the customer of a meter or billing error or (2) the customer informs the utility of a billing or metering error dispute or makes an informal complaint to the External Affairs section of the Commission.
- (c) In the event of an over-billing, the customer may elect to receive the refund as a credit to future billings or as a one-time payment. If the customer elects a one-time payment, the utility shall make the refund within 30 days. Such over-billings shall not be subject to interest.
- (d) In the event of under-billing, the customer may elect to enter into a payment arrangement on the under-billed amount. The payment arrangement shall be equal in length to the length of time during which the under-billing lasted. Such under-billings shall not be subject to interest.

3403. Applications for Service, Customer Deposits, and Third-Party Guarantee Arrangements.

- (a) A utility shall process an application for utility service which is made either orally or in writing and shall apply nondiscriminatory criteria with respect to the requirement of a cash deposit prior to commencement of service.
- (b) If billing records are available for a customer who has received service from the utility, the utility shall not require that person to make new or additional cash deposits to guarantee payment of current bills unless the records indicate recent or substantial delinquencies. All customers shall be treated without undue discrimination with respect to cash deposit requirements, pursuant to the utility's tariff.
- (c) A utility shall not require a cash deposit from an applicant for service who provides written documentation of a 12 consecutive month good credit history from the utility from which that person received similar service. For purposes of this paragraph, the 12 consecutive months must have ended no earlier than 60 days prior to the date of the application for service.
- (d) If a utility uses credit scoring to determine whether to require a cash deposit from an applicant for service or a customer, the utility shall have a tariff which describes, for each scoring model that it uses, the credit scoring evaluation criteria and the credit score limit which triggers a cash deposit requirement.
- (e) All utilities requiring deposits shall offer customers at least one non-cash alternative that does not require the use of the customer's social security number, in lieu of a cash deposit.
- (f) If a utility uses credit scoring, prior payment history with the utility, or customer-provided prior payment history with a like utility as a criterion for establishing the need for a cash deposit, the utility shall include in its tariff the specific evaluation criteria which trigger the need for a cash deposit.

- (g) If a utility denies an application for service or requires a cash deposit as a condition of providing service, the utility immediately shall inform the applicant for service of the decision and shall provide, within three business days, a written explanation to the applicant for service stating the reasons the application for service has been denied or a cash deposit is required.
- (h) No utility shall require any security other than either a cash deposit to secure payment for utility services or a third-party guarantee of payment in lieu of a cash deposit. In no event shall the furnishing of utility services or extension of utility facilities, or any indebtedness in connection therewith, result in a lien, mortgage, or other security interest in any real or personal property of the customer unless such indebtedness has been reduced to a judgment. Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a cash deposit or a new third party guarantor. (i) A cash deposit shall not exceed an amount equal to an estimated 90 days' bill of the customer, except in the case of a customer whose bills are payable in advance of service, in which case the cash deposit shall not exceed an estimated 60 days' bill of the customer. The cash deposit may be in addition to any advance, contribution, or guarantee in connection with construction of lines or facilities, as provided in the extension policy in the utility's tariffs.
- (j) A utility receiving cash deposits shall maintain records showing:
 - (I) The name of each customer making a cash deposit.
 - (II) The amount and date of the cash deposit.
 - (III) Each transaction, such as the payment of interest or interest credited, concerning the cash deposit.
 - (IV) Each premises where the customer receives service from the utility while the cash deposit is retained by the utility.
 - (V) If the cash deposit was returned to the customer, the date on which the cash deposit was returned to the customer.
 - (VI) If the unclaimed cash deposit was paid to the energy assistance organization, the date on which the cash deposit was paid to the energy assistance organization.
- (k) In its tariffs, a utility shall state its customer deposit policy for establishing or maintaining service. The tariff shall state the circumstances under which a cash deposit will be required and the circumstances under which it will be returned.
- (l) Each utility shall issue a receipt to every customer from whom a cash deposit is received. No utility shall refuse to return a cash deposit or any balance to which a customer may be entitled solely on the basis that the customer is unable to produce a receipt.
- (m) The payment of a cash deposit shall not relieve any customer from the obligation to pay current bills as they become due. A utility is not required to apply any cash deposit to any indebtedness of the customer to the utility, except for utility services due or past due after service is terminated.

- (n) A utility shall pay simple interest on a cash deposit at the percentage rate per annum as calculated by the Staff and in the manner provided in this paragraph.
 - (I) At the request of the customer, the interest shall be paid to the customer either on the return of the cash deposit or annually. The simple interest on a cash deposit shall be earned from the date the cash deposit is received by the utility to the date the customer is paid. At the option of the utility, interest payments may be paid directly to the customer or by a credit to the customer's account.
 - (II) The simple interest to be paid on a cash deposit during any calendar year shall be at a rate equal to the average for the period October 1 through September 30 (of the immediately preceding year) of the 12 monthly average rates of interest expressed in percent per annum, as quoted for one-year United States Treasury constant maturities, as published in the Federal Reserve Bulletin, by the Board of Governors of the Federal Reserve System. Each year, the Staff shall compute the interest rate to be paid. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is less than 25 basis points, the existing customer deposit interest rate shall continue for the next calendar year. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is 25 basis points or more, the newly calculated customer deposit interest rate shall be used. The Commission shall send a letter to each utility stating the rate of interest to be paid on cash deposits during the next calendar year. Annually following receipt of Staff's letter, if necessary, each utility shall file by advice letter or application, as appropriate, a revised tariff, effective the first day of January of the following year, or on an alternative date set by the Commission, containing the new rate of interest to be paid upon customers' cash deposits, except when there is no change in the rate of interest to be paid on such deposits.
- (o) A utility shall have tariffs concerning third-party guarantee arrangements and, pursuant to those tariffs, shall offer the option of a third party guarantee arrangement for use in lieu of a cash deposit. The following shall apply to third-party guarantee arrangements:
 - (I) An applicant for service or a customer may elect to use a third-party guarantor in lieu of paying a cash deposit.
 - (II) The third-party guarantee form, signed by both the third-party guarantor and the applicant for service or the customer, shall be provided to the utility.
 - (III) The utility may refuse to accept a third-party guarantee if the guarantor is not a customer in good standing at the time of the guarantee.
 - (IV) The amount guaranteed shall not exceed the amount which the applicant for service or the customer would have been required to provide as a cash deposit.
 - (V) The guarantee shall remain in effect until the earlier of the following occurs: it is terminated in writing by the guarantor; if the guarantor was a customer at the time of undertaking the guarantee, the guarantor is no longer a customer of the utility; or the customer has established a satisfactory payment record, as defined in the utility's tariffs, for 12 consecutive months.

- (VI) Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a cash deposit or a new third party guarantor.
- (p) A utility shall pay all unclaimed monies, as defined in § 40-8.5-103(5), C.R.S., that remain unclaimed for more than two years to the energy assistance organization. "Unclaimed monies" shall not include (1) undistributed refunds for overcharges subject to other statutory provisions and rules and (2) credits to existing customers from cost adjustment mechanisms.
 - (I) Monies shall be deemed unclaimed and presumed abandoned when left with the utility for more than two years after termination of the services for which the cash deposit or the construction advance was made or when left with the utility for more than two years after the cash deposit or the construction advance becomes payable to the customer pursuant to a final Commission order establishing the terms and conditions for the return of such deposit or advance and the utility has made reasonable efforts to locate the customer.
 - (II) Interest on a cash deposit shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the utility receives the cash deposit and ending on the date on which the cash deposit is paid to the energy assistance organization. If the utility does not pay the unclaimed cash deposit to the energy assistance organization within four months of the date on which the unclaimed cash deposition is deemed to be unclaimed or abandoned pursuant to subparagraph (o)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed cash deposit at the rate established pursuant to paragraph (n) of this rule plus 6%.
 - (III) If payable under the utility's line extension tariff provisions, interest on a construction advance shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the construction advance is deemed to be owed to the customer pursuant to the utility's extension policy and ending on the date on which the construction advance is paid to the energy assistance organization. If the utility does not pay the unclaimed construction advance to the energy assistance organization within four months of the date on which the unclaimed construction advance is deemed to be unclaimed or abandoned pursuant to subparagraph (o)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed construction advance at the rate established pursuant to paragraph (n) of this rule plus 6%.
- (q) A utility shall resolve all inquiries regarding a customer's unclaimed monies and shall not refer such inquiries to the energy assistance organization.
- (r) If a utility has paid unclaimed monies to the energy assistance organization, a customer later makes an inquiry claiming those monies, and the utility resolves the inquiry by paying those monies to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.
- (s) For purposes of paragraphs (p), (q), (r) of this rule, "utility" means and includes (1) a cooperative electric association which elects to be so governed and (2) a utility as defined in rule 3001(ff).

3404. Installment Payments.

- (a) In its tariffs, a utility shall have a budget or levelized payment plan available for its customers.
- (b) In its tariff, a utility shall have an installment payment plan which permits a customer to make installment payments if one of the following applies:
 - (I) The plan is to pay regulated charges from past billing periods and the past due amount arises solely from events under the utility's control (such as, without limitation, meter malfunctions, billing errors, utility meter reading errors, or failures to read the meter, except where the customer refuses to read the meter and it is not readily accessible to the utility). A utility shall advise a customer who is eligible for this type of plan of the customer's eligibility. At the request of the customer and at the customer's discretion, an installment payment plan under this subparagraph shall extend over a period equal in length to that during which the errors were accumulated and shall not include interest.
 - (II) The customer pays at least ten percent of the amount shown on the notice of discontinuance for regulated charges and enters into an installment payment plan on or before the expiration date of the notice of discontinuance.
 - (III) The customer pays at least ten percent of any regulated charges amount more than 30 days past due and enters into an installment payment plan on or before the last day covered by a medical certification. A customer who has entered into and failed to abide by an installment payment plan prior to receiving a medical certification shall pay all amounts that were due for regulated charges up to the date on which the customer presented a medical certification which meets the requirements of rule 3407(e)(IV) and then may resume the installment payment plan.
 - (IV) If service has been disconnected, the customer pays at least any collection and reconnection charges and enters into an installment payment plan. This subparagraph shall not apply if service was discontinued because the customer breached a prior payment arrangement.
- (c) Installment payment plans shall include the following amounts that are applicable at the time the customer requests a payment arrangement:
 - (I) The unpaid remainder of amounts due for regulated charges shown on the notice of discontinuance.
 - (II) Any amounts due for regulated charges not included in the amount shown on the notice of discontinuance which have since become more than 30 days past due.
 - (III) All current regulated charges contained in any bill which is past due but is less than 30 days past the due date.
 - (IV) Any new regulated charges contained in any bill which has been issued but is not past due.

- (V) Any regulated charges which the customer has incurred since the issuance of the most recent monthly bill.
 - (VI) Any collection fees as provided for in the utility's tariff, whether or not such fees have appeared on a regular monthly bill.
 - (VII) Any deposit, whether already billed, billed in part, or required by the utility's tariff, due for discontinuance or delinquency or to establish initial credit, other than a cash deposit required as a condition of initiating service.
 - (VIII) Any other regulated charges or fees provided in the utility's tariff (including without limitation miscellaneous service charges, investigative charges, and checks returned for insufficient funds charges), whether or not they have appeared on a regular monthly bill.
- (d) Within seven calendar days of entering into a payment arrangement with a customer, a utility shall provide the customer with a copy of this rule and a statement describing the payment arrangement. The statement describing the payment arrangement shall include the following:
- (I) The terms of the payment plan.
 - (II) A description of the steps which the utility will take if the customer does not abide by payment plan.
- (e) Except as provided in subparagraph (b)(I) of this rule, an installment payment plan shall consist, at a minimum, of equal monthly installments for a term selected by the customer but not to exceed six months. In the alternative, the customer may choose a modified budget billing, levelized payment, or similar tariffed payment arrangement in which the total due shall be added to the preceding year's total billing to the customer's premises, modified for any base rate or cost adjustment changes. The resulting amount shall be divided and billed in 11 equal monthly budget billing payments, followed by a settlement billing in the twelfth month, or shall follow other payment-setting practices consistent with the tariffed plan available.
- (f) For an installment payment plan entered into pursuant to this rule, the first monthly installment payment, and with the new charges (unless the new charges have been made part of the arrangement amount) shall be due on a date which is not earlier than the next regularly-scheduled due date of the customer who is entering into the installment payment plan. Succeeding installment payments, together with the new charges, shall be due in accordance with the due date established in the installment payment plan. Any payment not made on the due date established in the installment payment plan shall be considered in default. Any new charges that are not paid by the due date shall be considered past due, excluding those circumstances covered in subparagraph (b)(I) of this rule.
- (g) This rule shall not be construed to prevent a utility from offering any other installment payment plan terms to avoid discontinuance or terms for restoration of service, provided the terms are at least as favorable to the customer as the terms set out in this rule.

3405. Service, Rate, and Usage Information.

- (a) In addition to the requirement found in rule 1206, a utility shall inform its customers of any change proposed or made in any term or condition of its service if that change or proposed change will affect the quality of the service provided.
- (b) A utility shall transmit information provided pursuant to this rule through the use of a method (such as, without limitation, bill inserts or periodic direct mail) that will assure receipt by each customer.
- (c) Upon request, a utility must provide the following information to a customer:
 - (I) A clear and concise summary of the existing rate schedule applicable to each major class of customers for which there is a separate rate.
 - (II) An identification of each class whose rates are not summarized.
 - (III) A clear and concise explanation of the existing rate schedule applicable to the customer. This shall be provided within ten days of a customer's request or, in the case of a new customer, within 60 days of the commencement of service.
 - (IV) A clear and concise statement of the customer's actual consumption or degree-day adjusted consumption of electricity for each billing period during the prior year, unless such consumption data are not reasonably ascertainable by the utility.
 - (V) Any other information and assistance as may be reasonably necessary to enable the customer to secure safe and efficient service.

3406. Component and Source Disclosures.

- (a) Each utility shall provide, by a bill insert or a separate mailing, the following itemized information to its customers in April and October of each year:
 - (I) The percentage components, which include fixed and variable components, of the total average delivered price of electricity, residential or commercial, as applicable, attributable both to power supply and to power delivery for the previous calendar year. As used in this rule, "power supply" includes all generation, purchase power, and non-utility transmission components. As used in this rule, "power delivery" includes all utility transmission and distribution components.
 - (II) The power supply mix, which lists the fuel sources, expressed as a percentage of average annual power acquired and generated by the utility for the previous calendar year. The utility shall make reasonable efforts to identify and to include, to the extent that they are identifiable, all power supplied by non-utility generation sources in the power supply fuel source composition. Those sources which are not identifiable shall be listed as "imported, fuel source unknown." Fuel mixture information must use the following fuel type categories in the following order, rounded to the nearest tenth of one percent: biomass and waste; coal; geothermal; hydroelectric; natural gas; nuclear; solar; wind; and imported, fuel source unknown.

- (b) Price components and sources of power supply shall appear together in a format no larger than one page and shall be clearly legible, as follows:

ELECTRICITY FACTS

Price Components

Percentage components for an average monthly residential* electric bill.

	Residential * Service
Power Supply (Generation & Purchase)	xx%
Power Delivery (Transmission & Distribution)	xx%

Power Supply Mix

(Generation & Purchase)

Fuel sources used in power generation and purchase for the calendar year xxxx for all utility customers.

Fuel Type	%
Bio-mass and Waste	x.x%
Coal	x.x%
Geothermal	x.x%
Hydroelectric	x.x%
Natural Gas	x.x%
Nuclear	x.x%
Solar	x.x%
Wind	x.x%
Imported, Fuel Source Unknown	x.x%
Total	100%

3407. Discontinuance of Service.

- (a) A utility shall not discontinue the service of a customer for any reason other than the following:
- (I) Nonpayment of regulated charges.
 - (II) Fraud or subterfuge.
 - (III) Service diversion.
 - (IV) Equipment tampering.
 - (V) Safety concerns.
 - (VI) Exigent circumstances.
 - (VII) Discontinuance ordered by any appropriate governmental authority.

- (VIII) Properly discontinued service being restored by someone other than the utility when the original cause for proper discontinuance has not been cured.
- (b) A utility shall not discontinue service for nonpayment of any of the following:
- (I) Any amount which has not appeared on a regular monthly bill or which is not past due. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges.
 - (II) Any amount due on another account now or previously held or guaranteed by the customer, or with respect to which the customer received service, unless the amount has first been transferred either to an account which is for the same class of service or to an account which the customer has agreed will secure the other account. Any amount so transferred shall be considered due on the regular due date of the bill on which it first appears and shall be subject to notice of discontinuance as if it had been billed for the first time.
 - (III) Any amount due on an account on which the customer is or was neither the customer of record nor a guarantor, or any amount due from a previous occupant of the premises. This subparagraph does not apply if the customer is or was obtaining service through fraud or subterfuge or if rule 3401(c) applies.
 - (IV) Any amount due on any account for which the present customer is or was the customer of record, if another person established the account through fraud or subterfuge and without the customer's knowledge or consent.
 - (V) Any delinquent amount, unless the utility can supply billing records from the time the delinquency occurred.
 - (VI) Any debt except that incurred for service rendered by the utility in Colorado.
 - (VII) Any unregulated charge.
- (c) If the utility discovers any connection or device installed on the customer's premises, including any energy-consuming device connected on the line side of the utility's meter, which would prevent the meter from registering the actual amount of energy used, the utility shall do one of the following:
- (I) Remove or correct such devices or connections. If the utility takes this action, it shall leave at the premises a written notice which advises the customer of the violation, of the steps taken by the utility to correct it, and of the utility's ability to bill the customer for any estimated energy consumption not properly registered. This notice shall be left at the time the removal or correction occurs.
 - (II) Provide the customer with written notice that the device or connection must be removed or corrected within 15 days and that the customer may be billed for any estimated energy consumption not properly registered. If the utility elects to take this action and the device or connection is not removed or corrected within the 15 days permitted, then

within seven calendar days from the expiration of the 15 days, the utility shall remove or correct the device or connection pursuant to subparagraph (c)(I) of this rule.

- (d) If a utility discovers evidence that any utility-owned equipment has been tampered with or that service has been diverted, the utility shall provide the customer with written notice of the discovery. The written notice shall inform the customer of the steps the utility will take to determine whether non-registration of energy consumption has or will occur and shall inform the customer that the customer may be billed for any estimated energy consumption not properly registered. The utility shall mail or hand-deliver the written notice within three calendar days of making the discovery of tampering or service diversion.
- (e) A utility shall not discontinue service, other than to address safety concerns or in exigent circumstances, if one of the following is met:
 - (I) If a customer at any time tenders full payment in accordance with the terms and conditions of the notice of discontinuance to a utility employee authorized to receive payment, including any employee dispatched to discontinue service. Payment of a charge for a service call shall not be required to avoid discontinuance.
 - (II) If a customer pays, on or before the expiration date of the notice of discontinuance, at least one-tenth of the amount shown on the notice and enters into an installment payment plan with the utility, as provided in rule 3404.
 - (III) If it is between 12 Noon on Friday and 8 a.m. the following Monday; between 12 Noon on the day prior to and 8:00 a.m. on the day following any state or federal holiday; or between 12 Noon on the day prior to and 8:00 a.m. on the day following any day during which the utility's local office is not open.
 - (IV) If discontinuance of residential service would aggravate an existing medical condition or would create a medical emergency for the customer or a permanent resident of the customer's household, as evidenced by a written medical certification from a Colorado-licensed physician or health practitioner acting under a physician's authority. The certification shall show clearly the name of the customer or individual whose illness is at issue and the Colorado medical identification number, the telephone number, and the signature of the physician or health care practitioner acting under a physician's authority who certifies the medical emergency. The certification shall be incontestable by the utility as to medical judgment, although the utility may use reasonable means to verify the authenticity of the certification. A medical certification is effective on the date it is received by the utility and is valid to prevent discontinuance of service for 60 days. The customer may receive one 30-day extension by providing a second medical certification prior to the expiration of the original 60-day period. A customer may invoke this subparagraph only once in any 12 consecutive month period.

3408. Notice of Discontinuance of Service.

- (a) Except as provided in paragraphs (g) and (h) of this rule, a utility shall provide, by first class mail or by hand-delivery, written notice of discontinuance of service at least 15 days in advance of any proposed discontinuance of service. The notice shall be conspicuous and in easily understood language, and the heading shall contain, in capital letters, the following warning:

THIS IS A FINAL NOTICE OF DISCONTINUANCE OF UTILITY SERVICE AND CONTAINS IMPORTANT INFORMATION ABOUT YOUR LEGAL RIGHTS AND REMEDIES. YOU MUST ACT PROMPTLY TO AVOID UTILITY SHUT OFF.

- (b) The body of the notice of discontinuance under paragraph (a) of this rule shall advise the customer of the following:
- (I) The reason for the discontinuance of service and of the particular rule (if any) which has been violated.
 - (II) The amount past due for utility service, deposits, or other regulated charges, if any.
 - (III) The date by which an installment payment plan must be entered into or full payment must be received in order to avoid discontinuance of service.
 - (IV) How and where the customer can pay or enter into an installment payment plan prior to the discontinuance of service.
 - (V) That the customer may avoid discontinuance of service by entering into an installment payment plan with the utility pursuant to rule 3404 and the utility's applicable tariff.
 - (VI) That the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency.
 - (VII) That the customer has the right to dispute the discontinuance directly with the utility by contacting the utility, and how to contact the utility toll-free from within the utility's service area.
 - (VIII) That the customer has the right to make an informal complaint to the External Affairs section of the Commission in writing, by telephone, or in person, along with the Commission's address and local and toll-free telephone number.
 - (IX) That the customer has the right to file a formal complaint, in writing, with the Commission pursuant to rule 1302 and that this formal complaint process may involve a formal hearing.
 - (X) That in conjunction with the filing of a formal complaint, the customer has a right to file a motion for a Commission order ordering the utility not to disconnect service pending the outcome of the formal complaint process and that the Commission may grant the motion upon such terms as it deems reasonable, including but not limited to the posting of a cash deposit or bond with the utility or timely payment of all undisputed regulated charges.
 - (XI) That if service is discontinued for non-payment, the customer may be required, as a condition of restoring service, to pay reconnection and collection charges in accordance with the utility's tariff.
 - (XII) That qualified low-income customers may be able to obtain financial assistance to assist with the payment of the utility bill and that more detailed information on that assistance

may be obtained by calling the utility toll-free. The utility shall state its toll-free telephone number.

- (c) At the time it provides notice of discontinuance to the customer, a utility shall also provide written notice by first class mail or hand-delivery to any third-party the customer has designated in writing to receive notices of discontinuance or broken arrangement.
- (d) A discontinuance notice shall be printed in English and a specific language or languages other than English where the utility's service territory contains a population of at least ten percent who speak a specific language other than English as their primary language as determined by the latest U.S. Census information.
- (e) A utility shall explain and shall offer the terms of an installment payment plan to each customer who contacts the utility in response to a notice of discontinuance of service.
- (f) Following the issuance of the notice of discontinuance of service, and at least 24 hours prior to discontinuance of service, a utility shall attempt to give notice of the proposed discontinuance in person or by telephone both to the customer and to any third party the customer has designated in writing to receive such notices. If the utility attempts to notify the customer in person but fails to do so, it shall leave written notice of the attempted contact and its purpose.
- (g) If a customer has entered into an installment payment plan and has defaulted or allowed a new bill to remain unpaid past its due date, a utility shall provide, by first class mail or by hand-delivery, a written notice to the customer. The notice shall contain:
 - (I) A heading as follows: NOTICE OF BROKEN ARRANGEMENT.
 - (II) Statements that advise the customer:
 - (A) That the utility may discontinue service if it does not receive the monthly installment payment within ten days after the notice is mailed or hand-delivered.
 - (B) That the utility may discontinue service if it does not receive payment for the current bill within 30 days after its due date.
 - (C) That, if service is discontinued, the utility may refuse to restore service until the customer pays all amounts for regulated service more than 30 days past due and any collection or reconnection charges.
 - (D) That the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency.
- (h) A utility is not required to provide notice under this rule if one of the following applies:
 - (I) The situation involves safety concerns or exigent circumstances.
 - (II) Discontinuance is ordered by any appropriate governmental authority.
 - (III) Either rule 3407(c) or rule 3407(d) applies.

- (IV) Service, having been already properly discontinued, has been restored by someone other than the utility and the original cause for discontinuance has not been cured.
- (i) Where a utility knows that the service to be discontinued is used by customers in multi-unit dwellings, in places of business, or in a cluster of dwellings or places of business and the utility service is recorded on a single meter used either directly or indirectly by more than one unit, the utility shall issue notice as required in paragraphs (a) and (b) of this rule, except that:
 - (I) The notice period shall be 30 days.
 - (II) Such notice may include the current bill.
 - (III) The utility shall provide written notice to each individual unit, stating that a notice of discontinuance has been sent to the party responsible for the payment of utility bills for the unit and that the occupants of the units may avoid discontinuance by paying the next new bill in full within 30 days of its issuance and successive new bills within 30 days of issuance.
 - (IV) The utility shall post the notice in at least one of the common areas of the affected location.

3409. Restoration of Service.

- (a) Unless prevented from doing so by safety concerns or exigent circumstances, a utility shall restore, without additional fee or charge, any discontinued service which was not properly discontinued or restored as provided in rules 3407, 3408, and 3409.
- (b) Unless prevented by safety concerns or exigent circumstances, a utility shall restore service within 24 hours (excluding weekends and holidays), or within 12 hours if the customer pays any necessary after-hours charges established in tariffs, if the customer does any of the following:
 - (I) Pays in full the amount for regulated charges shown on the notice and any deposit and/or fees as may be specifically required by the utility's tariff in the event of discontinuance of service.
 - (II) Pays any reconnection and collection charges specifically required by the utility's tariff, enters into an installment payment plan, and makes the first installment payment, unless the cause for discontinuance was the customer's breach of such an arrangement.
 - (III) Presents a medical certification, as provided in rule 3407(e)(IV).
 - (IV) Demonstrates to the utility that the cause for discontinuance, if other than non-payment, has been cured.

3410. Refunds.

- (a) If it seeks to refund monies, a utility shall file an application for Commission approval of a refund plan.

- (b) The application for approval of a refund plan shall include, in the following order and specifically identified, the following information either in the application or in the appropriately identified attached exhibits:
 - (I) All the information required in rules 3002(b) and 3002(c).
 - (II) The reason for the proposed refund.
 - (III) A detailed description of the proposed refund plan, including the type of utility service involved, the service area involved, the class(es) of customers to which the refund will be made, and the dollar amount (both the total amount and the amount to be paid to each customer class) of the proposed refund. The interest rate on the refund shall be the current interest rate in the applying utility's customer deposits tariff.
 - (IV) The date the applying utility proposes to start making the refund, which shall be no more than 60 days after the filing of the application; the date by which the refund will be completed; and the means by which the refund is proposed to be made.
 - (V) If applicable, a reference (by docket number, decision number, and date) to any Commission decision requiring the refund or, if the refund is to be made because of receipt of monies by the applying utility under the order of a court or of another state or federal agency, a copy of the order.
 - (VI) A statement describing in detail the extent to which the applying utility has any financial interest in any other company involved in the refund plan.
 - (VII) A statement showing accounting entries under the Uniform System of Accounts.
 - (VIII) A statement that, if the application is granted, the applying utility will file an affidavit establishing that the refund has been made in accordance with the Commission's decision.
- (c) A utility shall pay 90% of all undistributed balances, plus associated interest, to the energy assistance organization. For purposes of this rule, a refund is deemed undistributed if, after good faith efforts, a utility is unable to find the person entitled to a refund within the period of time fixed by the Commission in its decision approving the refund plan.
- (d) A utility shall pay an undistributed refund to the energy assistance organization within four months after the refund is deemed undistributed. A utility shall pay interest on an undistributed refund from the time it receives the refund until the refund is paid to the energy assistance organization. The interest rate shall be equal to the interest rate set by the Commission pursuant to rule 3403(m).
- (e) Whenever a utility makes a refund, it shall provide written notice to those customers that it believes may be master meter operators. The notice shall contain:
 - (I) The definition of master meter operator, as set forth in these rules.
 - (II) A statement regarding a master meter operator's obligation to do the following:

- (A) To notify its end users of their right to claim, within 90 days, their proportionate share of the refund.
 - (B) After 90 days, if the unclaimed balance exceeds \$100, to remit the unclaimed balance to the energy assistance organization.
- (f) A utility shall resolve all inquiries regarding a customer's undistributed refund and shall not refer such inquiries to the energy assistance organization.
- (g) If a utility has paid an undistributed refund to the energy assistance organization, a customer later makes an inquiry claiming that refund, and the utility resolves the inquiry by paying that refund to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.
- (h) For purposes of paragraphs (c), (d), (e), (f), and (g) of this rule, "utility" means and includes (1) a cooperative electric association which elects to be so governed and (2) a utility as defined in rule 4001(ff).

3411. [Reserved]

3412. – 3499. [Reserved]

UNREGULATED GOODS AND SERVICES

3500. Special Definitions.

The following special definitions apply only to rules 3501 – 3505.

- (a) "Activity" means a business activity, product or service whether offered by a Colorado utility, a division of a Colorado utility, or an affiliate of a Colorado utility.
- (b) "Allocate" or "Allocated" or "Cost Allocation" means to distribute a joint or common cost to or from more than one activity or jurisdiction.
- (c) "Assigned Costs" or "Cost Assignment" means a cost that is specifically identified with a particular activity or jurisdiction and charged directly to that activity or jurisdiction. At no point in the process of making the cost assignment is an allocation applied.
- (d) "Cost Assignment and Allocation Manual" (CAAM) means the indexed document filed by a utility with the Commission that describes and explains the cost assignment and allocation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and ratebase cost components assigned or allocated to Colorado jurisdictional activities. It includes the cost assignment and allocation methods to segregate and account for costs between and among jurisdictions, between regulated and nonregulated activities, and between and among utility divisions.
- (e) "Division" means an activity conducted by a Colorado utility but not through a legal entity separate from the Colorado utility. It includes the electric, gas, or thermal activities of a Colorado utility and any nonregulated activities provided by the Colorado utility.

- (f) "Fully Distributed Cost" means the process of segregating, assigning, and allocating the revenues, expenses, assets, liabilities and ratebase amounts recorded in the utility's accounting books and records using cost accounting, engineering, and economic concepts, methods and standards. Fully distributed cost includes a return on investment in cases where assets are used.
- (g) "Fully Distributed Cost Study" is a cost study that reflects the result of the fully distributed revenues, expenses, assets, liabilities and ratebase amounts for the Colorado utility to and from the different activities, jurisdictions, divisions, and affiliates using cost accounting, engineering, and economic concepts, methods, and standards.
- (h) "Incidental Services" means non-tariffed or nonregulated services that have traditionally been offered incidentally to the provisions of tariff services where the revenues for all such services do not exceed:
 - (I) The greater of \$100,000 or one percent of the provider's total annual Colorado operating revenues for regulated services; or,
 - (II) Such amount established by the Commission considering the nature and frequency of the particular service.
- (i) "Jurisdictional" means having regulatory rate authority over a utility. Jurisdiction can be at a state or federal level.
- (j) "Regulated Activity" means any activity that is offered as a public utility service as defined in Title 40, Articles 1 to 7 C.R.S., and is regulated by the Commission or regulated by another state utility commission or the FERC, or any nonregulated activity which meets the criteria specified in rules 3502(g).
- (k) "Nonregulated Activity" means any activity that is not offered as a public utility service as defined in Title 40, Articles 1 to 7, C.R.S., and is not regulated by this Commission or another state utility commission or the FERC.
- (l) "Transaction" means the activity that results in the provision of products, services, or assets by one division or an affiliate to another division or an affiliate.

3501. Overview and Purpose.

The purpose of these rules is to establish cost assignment and allocation principles to assist the Commission in setting just and reasonable rates, as required by § 40-3-114 C.R.S. and to ensure that utilities do not use ratepayer funds to subsidize nonregulated activities, in accordance with § 40-3-114 C.R.S. In order to promote these purposes, these rules also specify information that utilities must provide to the Commission. In providing for review of a utility's specific cost allocations in other states and jurisdictions, the rules merely contemplate a methodology to allow interested parties to obtain complete information regarding cost allocations. These rules do not expressly or implicitly allow this Commission to order a utility to revise its cost allocations in other jurisdictions or states.

3502. Cost Assignment and Allocation Principles.

In determining fully distributed cost, the utility shall apply the following principles (listed in descending order of required application in (a), (b) and (c) below):

- (a) Tariffed services provided to an activity will be charged to the activity at the tariffed rates.
- (b) If only one activity or jurisdiction causes a cost to be incurred, that cost shall be directly assigned to that activity or jurisdiction.
- (c) Costs that cannot be directly assigned to either regulated or nonregulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and nonregulated activities or jurisdictions. Each cost category shall be fairly and equitably allocated between regulated and nonregulated activities or jurisdictions in accordance with the following principles:
 - (I) Cost causation. All activities or jurisdictions that cause a cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can easily be traced to the specific activity or jurisdiction.
 - (II) Variability. If the fully distributed cost study indicates a direct correlation exists between a change in the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship.
 - (III) Traceability. A cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that cause the cost to be incurred.
 - (IV) Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.
 - (V) Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator to be defined in the utility's CAAM.
- (d) For cost assignment and allocation purposes, the value of all transactions from the Colorado utility to a nonregulated activity shall be determined as follows:
 - (I) If the transaction involves a product or service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate.
 - (II) If the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the higher of the utility's fully distributed cost or market price. Market price shall be either the price charged by the utility, or if this condition cannot be met, the lowest price charged by another person for a comparable product or service.
 - (III) If the transaction involves the sale of an asset, the value of the transaction shall be the higher of net-book cost or market price. If the transaction involves the use of an asset,

the value of the transaction shall be the higher of fully distributed cost or market price. Market price shall be either the price charged by the utility or if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, when such prices are publicly available.

- (e) For cost assignment and allocation purposes, the value of all transactions from a nonregulated activity to the utility shall be determined as follows:
 - (I) If the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the lower of the fully distributed cost or the market price except if the transaction results from a competitive solicitation process then the value of the transaction shall be the winning bid price. Fully distributed cost in this circumstance, shall be the cost that would be incurred by the utility to provide the service internally. Market price shall be either the price charged by the supplying nonregulated activity or if that condition is not met, the lowest price charged by other persons in the market for a comparable product or service, when such prices are publicly available.
 - (II) If the transaction involves the sale of an asset, the value of the transaction shall be the lower of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be at the lower of fully distributed cost or market price. Market price shall be either the price charged by the nonregulated activity or, if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, where such prices are publicly available.
- (f) If it is impracticable for the utility to establish a market price pursuant to paragraphs (d) or (e), the utility shall provide a statement to that effect, including its reasons in its fully distributed cost study as well as its proposed method and amount for valuing the transaction. Parties in a Commission proceeding retain the right to advocate alternative market prices pursuant to paragraphs (d) and (e).
- (g) A utility may classify nonjurisdictional services as regulated if the services are rate-regulated by another agency (i.e., another state utility commission or the FERC) and where there are agency-accepted principles or methods for the development of rates associated with such services. This rule may apply, for example, to a provider's wholesale sales of electric power and energy. For such services, the utility shall identify the services in its manual, and account for the revenues, expenses, assets, liabilities, and ratebase associated with these services as if these services are regulated.
- (h) For cost assignment and allocation purposes, the value of all transactions between regulated divisions within a utility shall be determined as follows:
 - (I) If the transaction involves a service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate.
 - (II) If the transaction involves a service or function that is not provided pursuant to a tariff, the value of the transaction shall be at cost.

- (i) If the utility offers a service that is a combination of regulated and nonregulated activities (i.e., a bundled service), the utility shall assign and/or allocate costs to the regulated and nonregulated activities separately.
- (j) A utility may classify incidental activities as regulated activities. If an incidental activity is classified as a regulated activity, the utility shall clearly identify the activity as an incidental activity, and account for the revenues, expenses, assets, liabilities and ratebase items as if that activity were a regulated activity.
- (k) To the extent possible, all assigned and allocated costs between regulated and nonregulated activities should have an audit trail which is traceable on the books and records of the applicable regulated utility to the applicable accounts pursuant to the Federal Energy Regulatory Commission Uniform System of Accounts.
- (l) In a rate proceeding involving the calculation of revenue requirements, a complaint proceeding where cost assignments or allocations are at issue, or a proceeding where CAAM approval is sought, the utility or any party may advocate a cost allocation principle other than that already in use, if the Commission has already approved the principle for that cost. The party requesting the alternative approach shall have the burden of proving the need for an alternative principle and why the particular principle is appropriate for the particular cost.

3503. Cost Assignment and Allocation Manuals.

- (a) Each utility shall maintain on file with the Commission an approved indexed cost assignment and allocation manual which describes and explains the calculation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and ratebase cost components assigned or allocated to Colorado jurisdictional activities. It includes the calculation methods to segregate and account for costs between and among jurisdictions, between regulated and nonregulated activities, and between and among utility divisions.
- (b) Each utility shall include the following information in its CAAM:
 - (I) A listing of all regulated or nonregulated divisions of the Colorado utility together with an identification of the regulated or nonregulated activities conducted by each.
 - (II) A listing of all regulated or nonregulated affiliates of the Colorado utility together with an identification of which affiliates allocate or assign costs to and from the Colorado utility.
 - (III) A listing and description of each regulated and nonregulated activity offered by the Colorado utility. The Colorado utility shall provide a description in sufficient detail to identify the types of costs associated with the activity and shall identify how the activity is offered to the public and identify whether the Colorado utility provides the activity in more than one state. If an activity is offered subject to tariff, the Colorado utility may identify the tariff and the tariff section that describes the service offering in lieu of providing a service description.
 - (IV) A listing of the revenues, expenses, assets, liabilities and ratebase items by Uniform System of Accounts (USoA) account number that the utility proposes to include in its revenue requirement for Colorado jurisdictional activities including those items that are

partially allocated to Colorado as well as those items that are exclusively assigned to Colorado.

- (V) A detailed description showing how the revenues, expenses, assets, liabilities and ratebase items by account and sub-account are assigned and/or allocated to the Colorado utility's nonregulated activities, along with a description of the methods used to perform the assignment and allocations.
 - (VI) A description of each transaction between the Colorado utility and a nonregulated activity which occurred since the Colorado utility's prior CAAM was filed and, for each transaction, a statement as to whether, for this Commission's jurisdictional cost assignment and allocation purposes, the value of the transactions is at cost or market as applicable.
 - (VII) A description of the basis for how the assignment or allocation is made.
 - (VIII) If the utility believes that specific cost assignments or allocations are under the jurisdiction of another authority, the utility shall so state in its CAAM and give a written description of the prescribed methods. Nothing herein shall be construed to be a delegation of this Commission's ratemaking authority related to those assignments or allocations.
 - (IX) Any additional information specifically required by Commission order.
- (c) A utility may treat certain transactions as confidential pursuant to the Commission rules on confidentiality.
 - (d) Public Service Company of Colorado and Aquila, Inc. shall each initially file an application for approval of its CAAM within 180 days of the effective date of these rules. These utilities shall also simultaneously file a FDC study reflecting the assignment and allocation methods detailed and described in its manual.
 - (e) All other utilities shall each initially file an application for approval of its CAAM within 360 days of the effective date of these rules, or such other time to accommodate a staggered filing schedule if the Commission establishes one. These utilities shall also simultaneously file a FDC study reflecting the cost assignment and allocation methods detailed and described in its manual.
 - (f) Following the initial approval of its CAAM, the utility shall file an updated CAAM in each rate case proceeding where revenue requirements are determined or every five years following approval of the CAAM then in effect, whichever is earlier.
 - (g) The utility may, at its discretion, file an application seeking Commission approval of updates to its CAAM at any time.
 - (h) Whenever a utility files for approval of an update to its CAAM as a result of (f) or (g) above, the utility shall also simultaneously file a FDC study reflecting the results of the cost allocation methods in its updated manual.

- (i) Each utility shall maintain all records and supporting documentation concerning its CAAMs for so long as such manual is in effect or are subject to a complaint or a proceeding before the Commission.

3504. Fully Distributed Cost Study

- (a) The utility shall submit its fully distributed cost study in both electronic and paper format simultaneously with filing its CAAM for all Colorado divisions and activities.
- (b) The utility shall prepare a FDC study that identifies all the nonregulated activities provided by each division in Colorado. The FDC study shall show the revenues, expenses assets, liabilities and ratebase items assigned and allocated to each nonregulated activity. If the utility has more than one division (e.g., gas, electric, thermal or non-utility) in Colorado, the FDC study shall include a summary of all assigned and allocated costs by division.
- (c) In preparation of its FDC study, the utility shall complete an analysis of each nonregulated activity to identify the costs that are associated with and/or should be charged to each nonregulated activity to ensure each nonregulated activity is assigned and allocated the appropriate amount of revenues, expenses, assets, liabilities and ratebase items.
- (d) If the CAAM is filed in connection with a rate case, the FDC study shall be based on the same test year used in the utility's rate case filing. The utility's FDC study shall include revenues, expenses, assets, liabilities and ratebase items in order for the Commission to determine if all appropriate revenues, expenses, assets, liabilities and ratebase items have been appropriately assigned and allocated, and to determine the utility's compliance with the principles established in rule 3502. For each assignment and allocation the utility shall:
 - (I) Identify the revenues, expenses, assets, liabilities and ratebase items by account number, sub-account number and account description; and
 - (II) For each account in (I) above, identify the assignment and allocation method used to assign and allocate costs in sufficient detail to verify the assignment and allocation method used to assign and allocate costs to Colorado divisions and activities is accurate and consistent with the utility's CAAM methodology and reference the CAAM section that describes the allocation.
 - (III) Provide the test year dollar itemized amounts of revenues, expenses, assets, liabilities, and ratebase assigned and allocated to each Colorado division and non-regulated activity; the itemized amounts assigned and allocated to the Colorado utility for regulated activities; the itemized amounts assigned and allocated to the Colorado utility for Colorado nonregulated activities; and the itemized amounts assigned and allocated to other jurisdictions.
- (e) Each utility shall maintain all records and supporting documentation concerning its FDC study for so long as such study is in effect or are subject to a complaint or a proceeding before the Commission.

3505. Disclosure of Nonregulated Goods and Services.

Whenever a Colorado utility engages in the provision or marketing of nonregulated goods or services in Colorado that are not subject to Commission regulation, and the Colorado utility's name or logo is used in connection with the provision of such nonregulated goods and services in Colorado, there must be conspicuous, clear, and concise disclosure to prospective customers that such nonregulated goods and services are not regulated by the Commission. Such disclosure to prospective customers in Colorado shall be included in all Colorado advertising or marketing materials, proposals, contracts, and bills for nonregulated goods and services, regardless of whether the Colorado utility provides such nonregulated goods or services in Colorado directly or through a division or affiliate.

3506. – 3599. [Reserved]**LEAST-COST PLANNING****3600. Special Definitions.**

The following definitions apply to rules 3600 – 3615. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Availability factor" means the ratio of the time a generating facility is available to produce energy at its rated capacity, to the total amount of time in the period being measured.
- (b) "Annual capacity factor" means the ratio of the net energy produced by a generating facility in a year, to the amount of energy that could have been produced if the facility operated continuously at full capacity year round.
- (c) "End-use" means the light, heat, cooling, refrigeration, motor drive, or other useful work produced by equipment that uses electricity or its substitutes.
- (d) "Energy conservation" means the decrease in electricity requirements of specific customers during any selected time period, with end-use services of such customers held constant.
- (e) "Energy efficiency" means increases in energy conservation, reduced demand or improved load factors resulting from hardware, equipment, devices, or practices that are installed or instituted at a customer facility. Energy efficiency measures can include fuel switching.
- (f) "Heat Rate" means the ratio of energy inputs used by a generating facility expressed in BTUs (British Thermal Units), to the energy output of that facility expressed in kilowatt hours.
- (g) "Least-cost resource plan" or "plan" means a utility plan consisting of the elements set forth in rule 3604.
- (h) "Net present value of rate impact" means the current worth of the average annual rates associated with a particular resource portfolio, expressed in dollars per kilowatt hour in the year the plan is filed. The net present value of rate impact for a particular resource portfolio is first calculated by discounting the total annual revenue requirement by the appropriate discount rate. The discounted revenue requirement is then divided by the total utility kilowatt hour requirement for that year and averaged across the years of the planning period. The total annual revenue

requirement for each year of the planning period is the total expected future revenue requirements associated with a particular resource portfolio.

- (i) "Planning period" means the future period for which a utility develops its plan, and the period, over which net present value of rate impact for resources are calculated. For purposes of this rule, the planning period is twenty to forty years and begins from the date the utility files its plan with the Commission.
- (j) "Renewable resource" means any facility, technology, measure, plan or action utilizing a renewable "fuel" source such as wind; solar; biomass; geothermal; municipal, animal, waste-tire or other waste; or hydroelectric generation of twenty megawatts or less.
- (k) "Resource acquisition period" means the first six to ten years of the planning period, in which the utility acquires specific resources to meet projected electric system demand. The resource acquisition period begins from the date the utility files its plan with the Commission.
- (l) "Resources" means supply-side resources, energy efficiency, or renewable resources used to meet electric system requirements.
- (m) "Supply-side resource" means a resource that can provide electrical energy or capacity to the utility. Supply-side resources include utility owned generating facilities, and energy or capacity purchased from other utilities and non-utilities.
- (n) "Typical day load pattern" means the electric demand placed on the utility's system for each hour of the day.

3601. Overview and Purpose.

The purpose of these rules is to establish a process to determine the need for additional electric resources by Commission jurisdictional electric utilities, pursuant to the power to regulate public utilities delegated to the Commission by Article XXV of the Colorado Constitution and by §§ 40-2-123, 40-3-102, 40-3-111, and 40-4-101, C.R.S. It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. This process is intended to result in least-cost resource portfolios, taking into consideration projected system needs, reliability of proposed resources, expected generation loading characteristics, and various risk factors. The rules are intended to be neutral with respect to fuel type or resource technology.

3602. Applicability.

This rule shall apply to all jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority. Cooperative electric associations engaged in the distribution of electricity (*i.e.* rural electric associations) are exempt from these rules. Cooperative electric generation and transmission associations are subject only to reporting requirements as specified in rule 3605.

3603. Least-Cost Resource Plan Filing Requirements.

Jurisdictional electric utilities, as described in rule 3602, shall file a least-cost resource plan (plan) pursuant to these rules on or before October 31, 2003, and every four years thereafter. In addition to the required four-year cycle, a utility may file an interim plan, pursuant to rule 3604. If a utility chooses to file

an interim plan more frequently than the required four-year cycle, its application must state the reasons and changed circumstances that justify the interim filing. Each utility shall file an original and fifteen copies of the plan with the Commission.

3604. Contents of the Least-Cost Resource Plan.

The utility shall file a plan with the Commission that contains the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following:

- (a) A statement of the utility-specified resource acquisition period, and planning period. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire least-cost plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period lengths were chosen in light of the assessment of base-load, intermediate and peaking needs of the utility system.
- (b) An annual electric demand and energy forecast developed pursuant to rule 3606.
- (c) An evaluation of existing resources developed pursuant to rule 3607.
- (d) An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to rule 3608.
- (e) An assessment of need for additional resources developed pursuant to rule 3609.
- (f) A description of the utility's plan for acquiring these resources pursuant to rule 3610.
- (g) The proposed RFP(s) the utility intends to use to solicit bids for the resources to be acquired through a competitive acquisition process, pursuant to rule 3612.
- (h) An explanation stating whether current rate designs for each major customer class are consistent with the contents of its plan. The utility shall also explain whether possible future changes in rate design will facilitate its proposed resource planning and resource acquisition goals.

3605. Cooperative Electric Generation and Transmission Association Reporting Requirements.

Pursuant to the schedule established in rule 3603, each cooperative electric generation and transmission association shall report its forecasts, existing resource assessment, planning reserves, and needs assessment, consistent with the requirements specified in rules 3606, 3607, 3608(a) and 3609. Each cooperative generation and transmission association shall also file annual reports pursuant to rules 3614(a)(I) through 3614(a)(VI).

3606. Electric Energy and Demand Forecasts.

- (a) Forecast Requirements. The utility shall prepare the following energy and demand forecasts for each year within the planning period:

- (I) Annual sales of energy and coincident summer and winter peak demand in total and disaggregated among Commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states.
 - (II) Annual sales of energy and coincident summer and winter peak demand on a system wide basis for each major customer class.
 - (III) Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.
 - (IV) Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.
 - (V) Annual system losses and the allocation of such losses to the transmission and distribution components of the system. Coincident summer and winter peak system losses and the allocation of such losses to the transmission and distribution components of the systems.
 - (VI) Typical day load patterns on a system-wide basis for each major customer class. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.
- (b) Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy sales during the planning period.
- (c) Required Detail.
- (I) In preparing forecasts, the utility shall develop forecasts of energy sales and coincident summer and winter peak demand for each major customer class. The utility shall use end-use, econometric or other supportable methodology as the basis for these forecasts. If the utility determines not to use end-use analysis, it shall explain the reason for its determination as well as the rationale for its chosen alternative methodology.
 - (II) The utility shall explain the effect on its energy and coincident peak demand forecast of all existing energy efficiency and energy conservation programs for each major customer class, as well as any such measures that have been approved by the Commission but are not included in the forecasts.
 - (III) The utility shall maintain, as confidential, information reflecting historical and forecasted demand and energy use for individual customers in those cases when an individual customer is responsible for the majority of the demand and energy used by a particular rate class. However, when necessary in the least-cost resource plan proceedings, such information may be disclosed to parties who intervene in accordance with the terms of non-disclosure agreements approved by the Commission and executed by the parties seeking disclosure.

- (d) **Historical Data.** The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.
- (e) **Description and Justification.** The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.
- (f) **Format and Graphical Presentation of Data.** The utility shall include graphical presentation of the data to make the data more understandable to the public, and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.

3607. Evaluation of Existing Generation Resources.

- (a) **Existing Generation Resource Assessment.** The utility shall describe its existing generation resources, all utility-owned generating facilities for which the utility has obtained a CPCN from the Commission pursuant to C.R.S. § 40-5-101 at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following:
 - (I) Name(s) and location(s) of utility-owned generation facilities.
 - (II) Rated capacity and net dependable capacity of utility-owned generation facilities.
 - (III) Fuel type, heat rates, annual capacity factors and availability factors projected for utility-owned generation facilities over the planning period.
 - (IV) Estimated in-service dates for utility-owned generation facilities for which a CPCN has been granted but which are not in service at the time the plan under consideration is filed.
 - (V) Estimated remaining useful lives of existing generation facilities without significant new investment or maintenance expense.
 - (VI) The amount of capacity and/or energy purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy purchased pursuant to such contracts.
 - (VII) The amount of capacity and energy provided pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy provided pursuant to such wheeling or coordination agreements.
- (b) Utilities required to comply with these rules shall coordinate their plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms

and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.

(c) Existing Transmission Capabilities and Future Needs.

- (I) The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources. With respect to future needs, the utility shall explain the need for facilities based upon future load projections (including reserves). To the extent reasonably available, the utility shall include a description of the length and location of any additional facilities needed, their estimated costs, terminal points, voltage and megawatt rating, alternatives considered or under consideration, and other relevant information.
- (II) In order to equitably compare possible resource alternatives, the utility shall consider all transmission costs required by, or imposed on the system by, a particular resource as part of the bid evaluation criteria.

3608. Planning Reserve Margins.

- (a) The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).
- (b) The utility shall develop and justify planning reserve margins for each year of the resource acquisition period for the base case, high, and low forecast scenarios established under rule 3606, to include risks associated with: (1) the development of generation, (2) losses of generation capacity, (3) purchase of power, (4) losses of transmission capability, (5) risks due to known or reasonably expected changes in environmental regulatory requirements, and (6) other risks. The utility shall develop planning reserve margins for its system for each year of the planning period outside of the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.
- (c) Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for each year of the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to rule 3609. The Commission will consider approval of contingency plans only after the utility receives bids, as described in rule 3614(b)(II). The provisions of rule 3613(d) shall not apply to the contingency plans unless explicitly ordered by the Commission.

3609. Assessment of Need for Additional Resources.

By comparing the electric energy and demand forecasts developed pursuant to rule 3606 with the existing level of resources developed pursuant to rule 3607, and planning reserve margins developed pursuant to

rule 3608, the utility shall assess the need to acquire additional resources during the resource acquisition period.

3610. Utility Plan for Meeting the Resource Need.

- (a) The utility shall describe its least-cost resource plan for acquiring the resources to meet the need identified in rule 3609. The utility shall specify the portion of the resource need that it intends to meet as a part of a stand-alone voluntary tariff service, where all costs are separate from standard tariff services, if any. If the utility chooses to offer a stand-alone voluntary service, it must comply with the provisions of rule 3610(e); and the costs associated with any independent auditor will be assigned to the stand-alone voluntary service offering and will not be borne by the general body of utility ratepayers. The utility shall specify the portion of the resource need that it intends to meet through a competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.
- (b) The utility shall meet the resource need identified in the plan through a competitive acquisition process, unless the Commission approves an alternative method of resource acquisition. If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through a competitive acquisition process. In addition, the utility shall provide a cost-benefit analysis to demonstrate the reason(s) why the public interest would be served by acquiring the specific resource(s) through an alternative method of resource acquisition. The least-cost resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process. The utility shall also explain and shall justify how the alternative method of resource acquisition complies with the requirements of the Public Utility Regulatory Policies Act of 1978 and Commission rules implementing that act. The lesser of 250 megawatts or ten percent of the highest base case forecast peak requirement identified for the resource acquisition period shall be the maximum amount of power that the utility may obtain through such alternative method of resource acquisition (1) in any single resource acquisition period and (2) from any single specific resource, regardless of the number of resource acquisition periods over which the units, plants, or other components of the resource might be built or the output of the resource made available for purchase.
- (c) The utility shall have the flexibility to propose multiple acquisitions at various times over the resource acquisition period. However, the limits specified in paragraph (b) of this rule shall apply to the total resources acquired through an alternative method during an entire four-year least-cost planning cycle.
- (d) Each utility shall establish, and shall include as a part of its filing, a written bidding policy to ensure that bids are solicited and evaluated in a fair and reasonable manner. The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources under the utility's plan.
- (e) If the utility intends to accept proposals from the utility or from an affiliate of the utility, the utility shall include as part of its filing a written separation policy and the name of an independent auditor whom the utility proposes to hire to review, and to have report to the Commission on, the fairness of the competitive acquisition process. The independent auditor shall have at least five

years' experience conducting and/or reviewing the conduct of competitive electric utility resource acquisition, including computerized portfolio costing analysis. The independent auditor shall be unaffiliated with the utility and shall not have benefited, directly or indirectly, from employment or contracts with the utility in the preceding five years, except as an independent auditor under these rules. The independent auditor shall not participate in, or advise the utility with respect to, any decisions in the bid solicitation or bid evaluation process. The independent auditor shall conduct an audit of the utility's bid solicitation and evaluation process to determine whether it was conducted fairly. For purposes of such audit, the utility shall provide the independent auditor immediate and continuing access to all documents and data reviewed, used, or produced by the utility in its bid solicitation and evaluation process. The utility shall make all its personnel, agents, and contractors involved in the bid solicitation and bid evaluation available for interview by the auditor. The utility shall conduct any additional modeling requested by the independent auditor to test the assumptions and results of the bid evaluation analyses. Within sixty days of the utility's selection of final resources, the independent auditor shall file a report with the Commission containing the auditor's views on whether the utility conducted a fair bid solicitation and bid evaluation process, with any deficiencies specifically reported. After the filing of the independent auditor's report, the utility, other bidders in the resource acquisition process and other interested parties shall be given the opportunity to review and to comment on the independent auditor's report.

- (f) In selecting its final resource plan, the utility's objective shall be to minimize the net present value of rate impacts, consistent with reliability considerations and with financial and development risks. In its bid solicitation and evaluation process, the utility shall consider renewable resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases. Further, the utility shall grant a preference to such resources where cost and reliability considerations are equal.

3611. Exemptions from competitive acquisition.

The following resources need not be acquired through a competitive acquisition process and need not be included in an approved Least-Cost Plan prior to acquisition:

- (a) Emergency maintenance or repairs made to utility-owned generation facilities.
- (b) Capacity and/or energy from newly-constructed, utility-owned, supply-side resources with a nameplate rating of not more than 30 megawatts.
- (c) Capacity and/or energy from the generation facilities of other utilities or from non-utility generators pursuant to agreements for not more than a two year term (including renewal terms) or for not more than 30 megawatts of capacity.
- (d) Improvements or modifications to existing utility generation facilities that change the production capability of the generation facility site in question, by not more than 30 megawatts, based on the utility's share of the total power generation at the facility site and that have an estimated cost of not more than \$30 million.
- (e) Interruptible service provided to the utility's electric customers.

- (f) Modification to, or amendment of, existing power purchase agreements provided the modification or amendment does not extend the agreement more than four years, does not add more than 30 MW of capacity to the utility's system, and is cost effective in comparison to other supply-side alternatives available to the utility.
- (g) Utility investments in emission control equipment at existing generation plants.

3612. Request(s) For Proposals.

- (a) Purpose of the Request(s) for Proposals. The proposed RFP(s) filed by the utility shall be designed to solicit competitive bids to acquire additional resources pursuant to rule 3610.
- (b) Contents of the Request(s) for Proposals. The proposed RFP(s) shall include the bid evaluation criteria the utility plans to use in ranking the bids received. The utility shall also include in its proposed RFP(s): (1) base-load, intermediate, and/or peaking needs and preferred fuel type; (2) reasonable estimates of transmission costs for resources located in different areas; (3) the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; (4) the utility's proposed standard contract(s) for the acquisition of resources; (5) proposed contract term lengths; (6) discount rate; (7) general planning assumptions; and (8) any other information necessary to implement a fair and reasonable bidding program.

3613. Commission Review and Approval of Least-Cost Resource Plans.

- (a) Review on the Merits. The utility's plan, as developed pursuant to rule 3604, shall be filed as an application; shall meet the requirements of rules 3002(b) and 3002(c); and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure. The Commission may hold a hearing for the purpose of reviewing, and rendering a decision regarding, the contents of the utility's filed least-cost resource plan.
- (b) Basis for Commission Decision. Based upon the evidence of record, the Commission shall issue a written decision approving, disapproving, or ordering modifications, in whole or in part, to the utility's plan. If the Commission declines to approve a plan, either in whole or in part, the utility shall make changes to the plan in response to the Commission's decision. Within 60 days of the Commission's rejection of a plan, the utility shall file an amended plan with the Commission and shall provide copies to all parties who participated in the application docket concerning the utility's plan. All such parties may participate in any hearings regarding the amended plan.
- (c) Contents of the Commission Decision. The Commission decision approving or denying the plan shall address the contents of the utility's plan filed in accordance with rule 3604. If the record contains sufficient evidence, the Commission shall specifically approve or modify: (1) the utility's assessment of need for additional resources in the resource acquisition period; (2) the utility's plans for acquiring additional resources through the competitive acquisition process or through an alternative acquisition process; and (3) components of the utility's proposed RFP, such as the proposed evaluation criteria.
- (d) Effect of the Commission Decision. A Commission decision specifically approving the components of a utility's plan creates a presumption that utility actions consistent with that approval are prudent. Because the Commission will not approve a utility's selection of specific

resources, the Commission's approval of a plan creates no presumptions regarding those resources.

- (I) In a proceeding concerning the utility's request to recover the investments or expenses associated with new resources:
 - (A) The utility must present prima facie evidence that its actions were consistent with Commission decisions specifically approving or modifying components of the plan.
 - (B) To support a Commission decision to disallow investments or expenses associated with new resources on the grounds that the utility's actions were not consistent with a Commission approved plan, an intervenor must present evidence to overcome the utility's prima facie evidence that its actions were consistent with Commission decisions approving or modifying components of the plan. Alternatively, an intervenor may present evidence that, due to changed circumstances timely known to the utility or that should have been known to a prudent person, the utility's actions were not proper.
- (II) In a proceeding concerning the utility's request for a certificate of public convenience and necessity to meet customer need specifically approved by the Commission in its decision on the least-cost resource plan, the Commission shall take administrative notice of its decision on the plan. Any party challenging the Commission's decision regarding need for additional resources has the burden of proving that, due to a change in circumstances, the Commission's decision on need is no longer valid.

3614. Reports

- (a) Annual Progress Reports. The utility shall file with the Commission, and shall provide to all parties to the most recent least-cost planning docket, annual progress reports after submission of its plan application. The annual progress reports will inform the Commission of the utility's efforts under the approved plan. Annual progress reports shall also contain the following:
 - (I) An updated annual electric demand and energy forecast developed pursuant to rule 3606.
 - (II) An updated evaluation of existing resources developed pursuant to rule 3607.
 - (III) An updated evaluation of planning reserve margins and contingency plans developed pursuant to rule 3608.
 - (IV) An updated assessment of need for additional resources developed pursuant to rule 3609.
 - (V) An updated report of the utility's plan to meet the resource need developed pursuant to rule 3610 and the resources the utility has acquired to date in implementation of the plan.
 - (VI) In addition to the items required in subparagraphs(a)(I) through (a)(V), a cooperative electric generation and transmission association shall include in its annual report a full

explanation of how its future resource acquisition plans will give fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

- (b) Reports of the competitive acquisition process. The utility shall provide reports to the Commission concerning the progress and results of the competitive acquisition of resources. The following reports shall be filed:
 - (I) Within 30 days after bids are received in response to the RFP(s), the utility shall report: (1) the number of bids received, (2) the quantity of MW offered by bidders, (3) a breakdown of the number of bids and MW received by resource type, and (4) a description of the prices of the resources offered.
 - (II) If, upon examination of the bids, the utility determines that the proposed resources may not meet the utility's expected resource needs, the utility shall file, within 30 days after bids are received, an application for approval of a contingency plan. The application shall include the information required by rules 3002(b) and 3002(c), the justification for need of the contingency plan, the proposed action by the utility, the expected costs, and the expected timeframe for implementation.
 - (III) Within 45 days after the utility has selected the winning bidders, the utility shall report: (1) the number of winning bids; (2) the quantity of MW offered by the winning bidders; (3) a breakdown of the number and MW of winning bids by resource type, name, and location; and (4) a description of the prices of the winning bids.

3615. Amendment of an Approved plan.

The utility may file, at any time, an application to amend the contents of a plan approved pursuant to rule 3613. Such an application shall meet the requirements of rules 3002(b) and 3002(c), shall identify each proposed amendment, shall state the reason for each proposed amendment, and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

3616. – 3649. [Reserved]

3650. – 3665. [Reserved]

3666. – 3699. [Reserved]

APPEALS OF LOCAL GOVERNMENT LAND USE DECISIONS

3700. Scope and Applicability.

Rules 3700 through 3707 apply to all utilities or power authorities which seek to appeal a local government action concerning a major electrical facility.

3701. Definitions.

The following definitions apply to rules 3700 - 3707, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Local Government" means a county, a home rule or statutory city, town, a territorial charter city, a or city and county.
- (b) "Local government action" means (1) any decision, in whole or in part, by a local government which has the effect or result of denying a permit or application of a utility or power authority that relates to the location, construction, or improvement of a major electrical facility or (2) a decision which imposes requirements or conditions upon such permit or application that will unreasonably impair the ability of the utility or power authority to provide safe, reliable, and economical service to the public.
- (c) "Local land use decision" means the decision of a local government within its jurisdiction to plan for and regulate the use of land.
- (d) "Major electrical facility" shall have that meaning set forth in § 29-20-108(3)(a), (b), (c), and (d), C.R.S., or in any other applicable statute.
- (e) "Power authority" means an authority created pursuant to § 29-1-204, C.R.S.

3702. Precondition to Application.

In order for a utility or power authority to appeal a local government action to the Commission pursuant to this rule and pursuant to § 29-20-108, C.R.S., one or more of the following conditions must be met:

- (a) The utility or power authority has applied for or has obtained a certificate of public convenience and necessity from the Commission pursuant to § 40-5-101, C.R.S., to construct the major electrical facility that is the subject of the local government action.
- (b) A certificate of public convenience and necessity is not required for the utility or power authority to construct the major electrical facility that is the subject of the local government action.
- (c) The Commission has previously entered an order pursuant to § 40-4-102, C.R.S., that conflicts with the local government action.

3703. Applications.

- (a) To commence an appeal of a local government land use decision, a utility or power authority shall file with the Commission an application pursuant to this rule.
- (b) An application filed in accordance with §§ 29-20-108, C.R.S., and this rule shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:
 - (I) All of information required in rules 3002(b) and 3002(c).

- (II) A showing that one of the preconditions set out in rule 3702 has been met.
- (III) Identification of the major electrical facility.
- (IV) Identification of the local government action and its impact on the major electrical facility.
- (V) A statement of the reasons the applying utility or power authority believes that the local government action would unreasonably impair its ability to provide safe, reliable, and economical service to the public.
- (VI) The demonstrated need for the major electrical facility or reference to the application made to the Commission with respect to the major electrical facility and the resulting decision of the Commission regarding such facility.
- (VII) The extent to which the proposed facility is inconsistent with existing applicable local or regional land use ordinances, resolutions, or master or comprehensive plans.
- (VIII) Whether the proposed facility would exacerbate a natural hazard.
- (IX) Applicable utility engineering standards, including supply adequacy, system reliability, and public safety standards.
- (X) The relative merit, as determined through use of the normal system planning evaluation techniques of the utility or power authority, of any reasonably available and economically feasible alternatives proposed by the utility, the power authority, or the local government.
- (XI) The impact that the local government action would have on the customers of the utility or power authority who reside within and without the boundaries of the jurisdiction of the local government.
- (XII) The basis for the local government action. If available, the utility or power authority shall attach a copy of the local government action.
- (XIII) The impact the proposed facility would have on residents within the local government's jurisdiction including, in the case of a right-of-way in which facilities have been placed underground, whether those residents have already paid to place such facilities underground. If the residents have already paid to place facilities underground, the Commission will give strong consideration to that fact.
- (XIV) Information concerning how the proposed major electrical facility will affect the safety of residents within and without the boundaries of the jurisdiction of the local government.
- (XV) An attestation that the utility or power authority will, upon filing the application with the Commission, simultaneously send a copy of the application to the local government body which took the local government action which is the subject of the appeal.

3704. Public Hearing.

Pursuant to § 29-20-108(5)(b), C.R.S., and in addition to the formal evidentiary hearing on the appeal, the Commission shall take statements from the public concerning the appealed local government action at a public hearing held at a location specified by the local government.

3705. Prehearing Conference, Parties, and Public Notice.

- (a) In order to assist the parties in scheduling the public hearing, determining the scheduling of the evidentiary hearing, developing the list of persons to receive notice of these hearings, and addressing other pertinent issues, the Commission will hold a prehearing conference.
- (b) The Commission shall conduct a prehearing conference within 15 days after the application is deemed complete by the Commission.
- (c) The Commission shall join as an indispensable party the local government which took the contested local government action.
- (d) Ten days before the commencement of the prehearing conference, the local government shall submit to the parties and the Commission its preference for the location of the public hearing to be held in accordance with § 29-20-108(5)(b), C.R.S., and rule 3704.
- (e) The Commission will decide the date and time of the public hearing after receiving comments from the parties at the prehearing conference.
- (f) By the date of the prehearing conference, each party shall provide to the utility or power authority a list of individuals and groups to receive notice of the public hearing.
- (g) The utility or power authority shall give notice of the public hearing to the identified individuals and groups in a manner specified by the Commission. Notice may be accomplished by newspaper publication, bill insert, first class mail, or any other manner deemed appropriate by the Commission.
- (h) If the local government is unable to provide meeting space for the public hearing, and space needs to be acquired, then the utility or power authority shall bear any cost associated with the rental of such space for the public hearing.
- (i) The parties are encouraged to confer prior to the prehearing conference to develop a schedule for the filing of testimony and the dates for the formal evidentiary hearing.

3706. Denial of Appeal.

In accordance with § 29-20-108(5)(e), C.R.S., the Commission shall deny an appeal of a local government action if the utility or power authority has failed to comply with the following notification and consultation requirements:

- (a) A utility or power authority shall notify the affected local government of its plans to site a major electrical facility within the jurisdiction of the local government prior to submitting the preliminary or final permit application, but in no event later than filing a request for a certificate of public

convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or the filing of any annual filing with the Commission that proposes or recognizes the need for construction of a new major electrical facility or the extension of an existing facility. If a utility or power authority is not required to obtain a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or to file annually with the Commission to notify the Commission of the proposed construction of a new major electrical facility or the extension of an existing facility, the utility or power authority shall notify any affected local government of its intention to site a major electrical facility within the jurisdiction of the local government when such utility or power authority determines that it intends to proceed to permit and to construct the facility. Following such notification, the utility or power authority shall consult with the affected local governments in order to identify the specific routes or geographic locations under consideration for the site of the major electrical facility and to attempt to resolve land use issues that may arise from the contemplated permit application.

- (b) In addition to its preferred alternative within its permit application, the utility or power authority shall consider and present reasonable siting and design alternatives to the local government or shall explain why no reasonable alternatives are available.

3707. Procedural Rules.

Pursuant to § 29-20-108(5)(b), C.R.S., any appeal brought by a utility or power authority under this section shall be conducted in accordance with the procedural requirements of Article 6, Title 40, C.R.S., including § 40-6-109.5, C.R.S. Evidentiary hearings on any such appeals shall be conducted in accordance with § 40-6-109, C.R.S.

3708. – 3799. [Reserved]

MASTER METERS

3800. Applicability.

These rules are applicable to any person who purchases electric service from a utility for the purpose of delivery of that service to end-users whose aggregate usage is to be measured by a master meter or other composite measurement device.

3801. Definitions.

The following definitions apply to Rules 3800 - 3805, unless a specific statute or rule provides otherwise. In addition to these definitions, the definitions in rule 3001 apply.

- (a) "Check-meter" means a meter or other composite measurement device which is used by a master meter operator and which is used to determine electric consumption by end-users served by the master meter operator.
- (b) "Master meter" means a meter or other composite measurement device which a serving utility uses to bill a master meter operator.
- (c) "Master meter operator" or "MMO" means a person who purchases electric service from a serving utility for the purpose of delivering that service to end-users whose aggregate usage is measured by a master meter.

- (d) "Refund" means a refund, rebate, rate reduction, or similar adjustment.
- (e) "Serving utility" means the utility from which the master meter operator receives the electric service which the master meter operator then delivers to end-users.

3802. Exemption from Rate Regulation.

- (a) Pursuant to § 40-1-103.5, C.R.S., and by this rule, the Commission exempts from rate regulation under Articles 1 to 7 of Title 40, C.R.S., a master meter operator which is in compliance with rules 3803 and 3804.
- (b) A master meter operator which is not in compliance with rules 3803 and 3804 is subject to rate regulation under Articles 1 to 7 of Title 40, C.R.S., and shall comply with the applicable rules.

3803. Exemption Requirements.

- (a) In order to retain its exemption from rate regulation, a MMO shall do the following:
 - (I) As part of its billing for utility service, the MMO shall charge its end-users only the actual cost billed to the MMO by the serving utility. The MMO shall not charge end-users for any other costs (such as, without limitation, the costs of construction, maintenance, financing, administration, metering, or billing for the equipment and facilities owned by the MMO) in addition to the actual costs billed to the MMO by the serving utility.
 - (II) If the MMO bills its end-users separately for service, the sum of such billings shall not exceed the amount billed to the MMO by the serving utility.
 - (III) If the MMO bills its end-users separately for service, the MMO shall pass on to its end-users all refunds the MMO receives from the serving utility or otherwise.
 - (IV) The MMO shall establish procedures for giving notice of a refund to those who are not current end-users but who were end-users during the period for which the refund is paid.
 - (V) A master meter operator shall retain, for a period of not less than three years, all records of original utility billings made to the master meter operator and all records of billings made by the master meter operator to its end-users.
- (b) In order to retain its exemption from rate regulation, a MMO shall not resell electricity for profit. Resale is a basis for revocation of an exemption from rate regulation.
- (c) A MMO may check-meter tenants, lessees, or other persons to whom the electricity ultimately is distributed but may do so only if the following conditions are met:
 - (I) The check-meter is used solely for the purpose of reimbursing the MMO by means of an appropriate allocation procedure.
 - (II) The MMO does not receive more than the actual amount billed to the MMO by the serving utility.

3804. Refunds.

(a) When a serving utility notifies a MMO of a refund or when a refund is otherwise made, a MMO shall notify its end-users of the refund and shall inform the end-users that they may claim the refunds within 90 days after receipt of the notice. The notification shall be made either by first-class mail with a certificate of mailing or by inclusion in any monthly or more frequent regular written communication. The MMO shall also notify former customers who were end-users during the period for which the refund is made. The MMO shall give the notice required by this paragraph within 30 days of notification about the refund or, if there is no prior notification, within 30 days of receipt of the refund.

(b) A MMO may retain any portion of a refund which rightfully belongs to the MMO.

(c) If the aggregate amount of a refund which remains unclaimed after 90 days exceeds \$100, the MMO shall contribute that unclaimed amount to the energy assistance organization in accordance with rules 3410(d), (f), and (g). If the aggregate amount which remains unclaimed after 90 days does not exceed \$100, the MMO may retain the aggregate amount.

(d) A MMO shall pay interest on undistributed refunds in accordance with rule 3410(d).

3805. Complaints, Penalties, and Revocation of Exemption.

(a) Pursuant to rules 1301 and 1302, a person (including without limitation anyone subject to a master meter) may make an informal complaint to the External Affairs section of the Commission or may file a formal complaint with the Commission with the respect to an alleged violation of rules 3803 and 3804.

(b) As a result of a complaint or on its own motion, the Commission will investigate complaints concerning MMOs. If the Commission determines after investigation that an MMO has violated any of the requirements of rules 3803 and 3804, the MMO may have its exempt status revoked or may be subject to penalties as set forth in § 40-7-107, C.R.S., or both.

3806. – 3899. [Reserved]**SMALL POWER PRODUCERS AND COGENERATORS****3900. Scope and Applicability.**

Rules 3900 through 3954 apply to utilities which purchase power from small power producers and cogenerators. These rules also apply to small power producers and cogenerators which sell power to utilities. However, for qualifying facilities with a nameplate rating of 10MW or less, to the extent that Rules 3900 through 3954 are inconsistent with Rule 3665, Rule 3665 shall control.

3901. Definitions.

The following definitions apply to rules 3900 through 3954, except where a specific rule or statute provides otherwise. In addition to the definitions stated here, the definitions found in the Public Utilities Law, in the Public Utility Regulatory Policies Act of 1978, and in the federal regulations which are incorporated by reference apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Avoided cost" means the incremental or marginal cost to an electrical utility of electrical energy or capacity, or both, which, but for the purchase of such energy and/or capacity from qualifying facility or qualifying facilities, the utility would generate itself or would purchase from another source.
- (b) "Qualifying facility" means any small power production facility or cogeneration facility which is a qualifying facility under federal law.
- (c) "Rate" means any price, rate, charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electrical energy or capacity; any rule or practice respecting any such rate, charge, or classification; and any contract pertaining to the sale or purchase of electrical energy or capacity.

3902. Avoided Costs.

- (a) Each utility shall pay qualifying facilities a rate for energy and capacity purchases based on the utility's avoided costs..
- (b) Each electric utility shall file tariffs setting forth standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.
- (c) A utility shall use a bid or an auction or a combination procedure to establish its avoided costs for facilities with a design capacity of greater than 100 kilowatts. The utility is obligated to purchase capacity or energy from a qualifying facility only if the qualifying facility is awarded a contract under the bid or auction or combination process.
- (d) If a utility can demonstrate to the Commission that a qualifying facility should receive a different rate from that established by these rules, the Commission may authorize such. The burden of establishing such different rate shall be on the utility, and the rate shall be based on the utility's system wide costing principles and other appropriate load and cost data.
- (e) Nothing in this rule requires a utility to pay more than its avoided costs of energy and capacity, of energy, or of capacity for purchases from qualifying facilities.

3903. Payment of Interconnection Costs.

- (a) Each qualifying facility shall pay the cost of interconnecting with an electric utility for purchases and sales of capacity and energy. To the extent that interconnection costs can be determined in advance of interconnection, each electric utility shall establish the cost of interconnection for purchases of energy and capacity. The interconnection costs shall be fair, reasonable, and nondiscriminatory to each qualifying facility.
- (b) The utility and qualifying facility may agree to an installment payment arrangement for interconnection costs.

3904. – 3909. [Reserved]

3910. Standards for Operating Reliability and Safety.

Rules 3910 through 3929 establish standards, as authorized by 18 C.F.R. § 292.308, to ensure the safe and reliable interconnected operations of qualifying facilities with utilities regulated by the Commission.

3911. Responsibility of a Utility to Provide Quality Service.

- (a) A utility shall provide substantially the same quality of service to its customers and to the qualifying facility after interconnection of the qualifying facility as the utility provided prior to interconnection of the qualifying facility. The interconnection of the qualifying facility to the utility shall not degrade the utility's quality of service to its other customers. The qualifying facility shall pay for the interconnection facilities necessary to preserve the utility's quality of service to its other customers.
- (b) At the request of a qualifying facility or a utility prior to interconnection, a utility may evaluate the quality of service to be provided to the qualifying facility. The cost of conducting an evaluation shall be included as an interconnection cost of a qualifying facility. The evaluation may be used for the following purposes:
 - (I) To estimate the effects of interconnection on the quality of service to be provided.
 - (II) To establish the quality of service that a utility shall provide to a qualifying facility after interconnection.
- (c) If the qualifying facility desires a superior quality of service to that established by an evaluation performed pursuant to paragraph (b) of this rule, any increased cost shall be an interconnection cost of the qualifying facility.

3912. Submission of Design Information by a Qualifying Facility.

- (a) This rule shall apply only to qualifying facilities with nameplate ratings greater than 10MW. For facilities 10MW or less, see Rule 3655.
- (b) Any person seeking to establish interconnected operations as a qualifying facility shall provide to the utility with which it proposes to interconnect detailed design information of its proposed facilities at least 150 days prior to the proposed interconnection date. At any time after submission of design information, the utility and the qualifying facility may agree to an interconnection date sooner than 150 days. At the time it provides the detailed design information to the utility, the qualifying facility also shall provide the utility with a copy of all available manufacturers' literature for the equipment to be installed, including installation and operating instructions.
- (c) The design information submitted by a qualifying facility shall be sufficient to enable a utility to assess the impact of the proposed interconnection on the utility's system, operating plans, and system expansion plans.
- (d) Within 25 days after the receipt of design information, or such longer period as agreed by them, a utility shall notify a qualifying facility whether the design information is adequate or whether additional information is required. If additional information is required, the utility shall specify in

writing what additional information is needed; and the qualifying facility shall promptly submit the additional information.

3913. Conferences between a Utility and a Qualifying Facility.

- (a) This rule shall apply only to qualifying facilities with nameplate ratings greater than 10MW. For facilities 10MW or less, see Rule 3655.
- (b) No later than 30 days after a qualifying facility has provided design information to a utility, the utility and the qualifying facility shall confer.
- (c) At the conference, the utility shall provide the qualifying facility with the names of governmental agencies which have requirements (such as, without limitation, electrical codes, construction codes, sizing criteria, setback distances, physical clearances, protective devices, inspections, and grounding practices) regulating interconnection.
- (d) At the conference, the utility shall inform the qualifying facility of these rules and of the system operation requirements and the safety standards and procedures (such as, without limitation, harmonic content for output voltage levels, recommended use of induction generators, line-commutated inverters, and reliable disconnection equipment) required for interconnection.

3914. Establishment of Requirements for a Qualifying Facility.

- (a) Within 25 days after submission of complete design information by a qualifying facility, a utility shall:
 - (I) Establish written operations requirements for the qualifying facility so that interconnection with the qualifying facility will not cause abnormal operation of the utility's protective equipment.
 - (II) Inform the qualifying facility of the existing phase conductors and utility's requirements for system electrical phase sequence/rotation available to the qualifying facility and encourage the qualifying facility to use the existing phasing for the proposed interconnection. The utility shall inform the qualifying facility that any phase imbalances may affect the safety of the proposed service or neighboring customer's loads.
- (b) In the event that phased loadings of interconnection cause phase imbalances, the cost of equipment to correct the imbalances shall be an interconnection cost of the qualifying facility.

3915. Compliance with Requirements and Rule Standards.

- (a) No utility shall interconnect with a qualifying facility until the qualifying facility has established, to the satisfaction of the utility, that it has complied with the utility's requirements for interconnected operations and the standards established in rules 3910 to 3929.
- (b) When a qualifying facility determines that it has complied with all of the requirements of a utility and the standards established in these rules for interconnected operations, the qualifying facility shall give written notice of that fact to the utility. Within 25 days after receipt of that notice, the utility and the qualifying facility shall arrange for an onsite inspection of the qualifying facility. The

utility shall inspect the facilities related to the qualifying facility's interconnection with the utility. The qualifying facility shall provide the personnel necessary to operate the facility in order to demonstrate to the utility the proper operation of the qualifying facility's equipment.

- (I) If the utility determines from the inspection that the qualifying facility has complied with all of the requirements of the utility and the standards established in these rules, the utility shall certify in writing that the qualifying facility complies.
 - (II) If the utility determines that the qualifying facility has failed to comply with any requirement of the utility or any standard established in these rules, the utility shall notify the qualifying facility in writing of the requirements or standards that the qualifying facility must meet for interconnection. Upon compliance, the qualifying facility shall give written notice to the utility; and the parties shall proceed as provided in paragraph (b) of this rule.
- (c) When the qualifying facility has obtained compliance certification, the qualifying facility and the utility shall schedule a date for the initial energizing and start-up testing of the qualifying facility's generating equipment. The utility at its option may be present at this test.
- (I) At the conclusion of the test, the utility shall certify in writing whether the qualifying facility may commence interconnected operations.
 - (II) If the qualifying facility fails the start-up test, the utility shall so notify the qualifying facility in writing and within five business days. When the qualifying facility has corrected the deficiencies, the parties shall schedule a new start-up test; and the parties shall proceed as provided in paragraph (c) of this rule.
- (d) In the event of a disagreement between a qualifying facility and a utility regarding (1) compliance by the qualifying facility with the utility's requirements or with the standards established in these rules or (2) the qualifying facility's failure of the start-up test, either party may file with the Commission a petition for a declaratory order under rule 1304(j) seeking resolution of the disagreement.
- (e) In the event that either party files a petition for a declaratory order, the Commission shall enter an order resolving the dispute. The qualifying facility or the utility shall comply with the Commission's order prior to interconnection.

3916. Code Certification by a Qualifying Facility.

- (a) A qualifying facility shall provide a utility with certification that it has complied with all applicable governmental codes (such as, without limitation, electrical codes, construction codes, sizing criteria, set-back distances, physical clearances, protective devices, inspections, and grounding practices).
- (b) A qualifying facility shall obtain all necessary certifications at its own cost.

3917. Utility Access to Premises of a Qualifying Facility.

- (a) A utility shall have access to a qualifying facility prior to construction to determine if minimum setback distances and physical clearances will be met for the safety of the utility's equipment. The cost of said inspection shall be included as an interconnection cost of the qualifying facility.
- (b) A utility shall have access to a qualifying facility to repair, to maintain, or to retrieve any of the utility's equipment affected by a failure of the utility's or qualifying facility's equipment.
- (c) A utility shall have access to a qualifying facility to conduct an inspection for the purpose stated in rule 3921(d).
- (d) A utility shall have access to a qualifying facility to conduct an inspection pursuant to the procedures established pursuant to rule 3927(b).
- (e) A utility shall have access to a qualifying facility to conduct an inspection pursuant to rule 3927(d).
- (f) A utility shall have access to a qualifying facility to conduct an inspection pursuant to rule 3927(e).

3918. Coordination of Circuit Protection Equipment.

- (a) Prior to interconnection and at the earliest time possible after a qualifying facility provides its complete design information, but in no event later than 25 days after submission of complete design information, a utility shall provide a written statement to the qualifying facility as to whether the utility's circuit protection equipment can accommodate the equipment of the qualifying facility.
- (b) A utility shall evaluate the effects of a proposed interconnection, together with the aggregate effects of all other interconnections, on the utility's installed circuit protection equipment. Costs of the evaluation shall be an interconnection cost paid by the qualifying facility. (c) As part of normal planning, a utility shall evaluate the interaction between a qualifying facility's operations and the utility's installed circuit protection equipment. The cost of evaluation shall be an interconnection cost of the qualifying facility.
- (d) If the design of a qualifying facility causes replacement or significant re-coordination of the utility's circuit protection equipment, or if the design reasonably can be expected to require extraordinary operation of the utility's installed protection equipment, the utility shall not interconnect with the qualifying facility. The utility shall decline to interconnect until either the design has been modified to eliminate the problems or specific modified designs for the interconnection are established. Replacement and re-coordination costs shall be an interconnection cost of the qualifying facility.
- (e) A qualifying facility shall provide the utility with a description of the qualifying facility's electrical and mechanical equipment sufficient for the utility to determine the safety and adequacy of its installed service drops and supply equipment. The qualifying facility shall provide this information at the time it submits its design information to the utility.

3919. Installation of Protective Equipment by a Qualifying Facility to Accommodate Protection Equipment of a Utility.

- (a) Within 25 days after a qualifying facility submits its complete design information, a utility shall notify the qualifying facility of any necessity to install protective equipment to accommodate the utility's system protection equipment.
- (b) Such notification shall be made in writing and shall list the specific types of protective equipment required and the operations of the utility which necessitate protection.
- (c) The qualifying facility shall be responsible for installing protective equipment to accommodate the utility's system protection equipment. The cost of this installation shall be an interconnection cost of the qualifying facility.
- (d) A utility shall not be responsible for the effects on a qualifying facility's equipment and systems that are caused by the utility's system or equipment.

3920. Grounding Qualifying Facility Equipment.

- (a) A utility shall establish grounding practices that are commensurate with those in the area, taking into consideration soil conditions, the nature of other loads in the area, and the utility's experience. Grounding practices shall be consistent with applicable national, state, and local codes.
- (b) A qualifying facility shall ground all equipment to meet governmental codes and the utility's requirements.
- (c) A utility shall advise, in writing, a qualifying facility of its grounding requirements within 25 days after the qualifying facility submits its complete design information.
- (d) If the grounding of a qualifying facility's equipment degrades safety, necessitating improvements or modifications of the interconnection, the utility shall have the right to approve the improvements or modifications made to the interconnection to assure that they are sufficient to address the safety issue caused by the degradation. The qualifying facility shall bear the responsibility for and the cost of such improvements or modifications.
- (e) In the event that grounding of a qualifying facility causes electro-magnetic interference with telephone service, radio or television reception, or the operation of other electrical devices, the qualifying facility shall make the necessary grounding modifications to remove such interference. The cost of such modifications shall be an interconnection cost of the qualifying facility.
- (f) No qualifying facility shall commence interconnected operations until it obtains written certification that it has complied with all applicable governmental codes and until the utility approves the grounding of the qualifying facility's equipment.

3921. Standards for Harmonics and Frequency.

- (a) A utility shall establish non-discriminatory standards for the harmonic content of power and energy generated by qualifying facilities.

- (b) No qualifying facility shall commence interconnected operations until it establishes, to the satisfaction of the utility, that it will produce power and energy at a fundamental frequency of 60 HZ and that such power will not exceed the utility's established standards for harmonic content.
- (c) A utility shall not be responsible for onsite interference caused by harmonics, failure of motors, interference with telephone service or television or radio reception, and other manifestations of degraded quality of service which are caused by the failure of a qualifying facility to produce power and energy at 60 HZ.
- (d) A qualifying facility shall not operate its generators in such a fashion as to impact negatively the utility's or the utility's customers' voltage range or other voltage characteristics. The qualifying facility shall have adequate voltage regulation and related protective and control equipment as required by the utility.
- (e) A qualifying facility shall operate within the utility's power factor and voltage characteristic requirements.

3922. Interconnection at Different Voltage Levels.

- (a) A qualifying facility shall interconnect with a utility at the utility's established voltage level.
- (b) An interconnection at a voltage level that requires the utility to install different or additional protective equipment, or that requires the utility to make other modifications of its system, shall be an interconnection cost of the qualifying facility.

3923. Types of Generators and Inverting Equipment.

- (a) A utility shall establish standards to encourage qualifying facilities to use generators that minimize the safety hazard associated with the possibility of reverse power flow during periods of line outages.
- (b) A utility shall adopt power factor standards at the point of interconnection. Such standards shall recognize that a qualifying facility may not produce excessive reactive power during off-peak conditions and may not consume excessive reactive power during on-peak conditions. The qualifying facility shall be responsible for installing, at its expense, the equipment necessary to maintain power factor requirements.
- (c) If a qualifying facility's abnormal power factor causes deleterious effects on a utility's system,, unless otherwise provided by contract, the utility shall correct the deleterious effects on its system at the expense of the qualifying facility. Deleterious effects on a qualifying facility's system caused by its abnormal power factor shall be corrected by the qualifying facility at its own expense.

3924. System Protection Equipment.

- (a) Prior to interconnection, a qualifying facility shall install protective equipment that will automatically disconnect its generating equipment from a utility's power lines in the event of failure of the qualifying facility's generating equipment, a power line outage, or a nearby system fault.

- (I) The protective equipment, or separate equipment, shall have the ability to isolate the energy generated or supplied by a utility or by a qualifying facility. The equipment shall be accessible to and by the utility and the qualifying facility.
- (II) A utility shall have the right to operate the protective equipment whenever, in its judgment, it is necessary to maintain safe operating conditions or whenever the operations of a qualifying facility adversely affect the utility's system.
- (III) A qualifying facility shall have the right to operate the protective equipment whenever, in its judgment, it is necessary to maintain safe operating conditions or whenever the operations of a utility adversely affect the qualifying facility's equipment.
- (IV) Protective equipment that isolates a qualifying facility's generation shall be lockable by a utility only in the open position. Equipment that isolates a utility's generation or supply shall be lockable by a qualifying facility only in the open position. This equipment shall be installed so that there can be visual verification that the equipment is locked in the open position.
- (b) Prior to interconnection, a utility shall require a qualifying facility to demonstrate the proper functioning and operation of its protective equipment to the satisfaction of the utility.
- (c) A qualifying facility shall install overcurrent protection between major components of all switched interconnections.
- (d) A qualifying facility shall install protective relaying equipment to confine the effects of faults, lightning strikes, or other abnormalities and to protect its and a utility's equipment.
- (e) Prior to making significant modifications to its equipment, a qualifying facility shall notify a utility with which the QF is interconnected of the proposed modifications. If a qualifying facility plans to make significant modifications to its equipment, or if future difficulties arise on the systems of the qualifying facility or the utility as a result of the interconnection, the utility may require different or additional protective equipment or may require modifications as a condition of continued interconnected operations. The cost of such protective equipment or modifications shall be a cost of the qualifying facility.
- (f) No specific number of system protective devices is required by this rule.

3925. Meters.

- (a) A utility shall own, install, and maintain meters and associated metering equipment to measure the generation of a qualifying facility.
- (b) A qualifying facility shall supply, at no expense to the utility, a suitable location for the installation of metering equipment.
- (c) The cost of meters and associated metering equipment, their installation, and their maintenance shall be an interconnection cost of the qualifying facility.

3926. Maintenance and Inspection of a Qualifying Facility.

- (a) Prior to interconnection, a qualifying facility shall establish a planned maintenance schedule containing dates, times, and procedures. No qualifying facility shall commence interconnected operations until the utility approves the proposed maintenance schedule. The utility shall not withhold approval unreasonably.
- (b) A utility shall establish written procedures for inspecting a qualifying facility and shall provide a copy of the procedures to the qualifying facility prior to interconnection. Inspection procedures may be modified on a case-by-case basis.
- (c) A qualifying facility shall keep records of maintenance, and a utility shall keep records of inspections. Each shall have access to the records of the other.
- (d) A utility may inspect a qualifying facility, on demand, to determine if the qualifying facility is complying with the previously-approved maintenance schedule and is safely operating all protective equipment.
- (e) A utility may inspect the qualifying facility and its records, on demand, to determine if the qualifying facility is, or has been, reselling the utility's energy and/or capacity to the utility.
- (f) Personnel from both a utility and a qualifying facility shall have the right to witness inspections. For inspections to determine safety or the reselling of the utility's energy or capacity to the utility, the utility shall inform the qualifying facility that it intends to inspect the facility. If the qualifying facility declines, the inspection shall be conducted without the presence of qualifying facility personnel. If the qualifying facility fails the inspection, the utility shall have the right to disconnect the qualifying facility from the utility's system until the qualifying facility can demonstrate the proper functioning of the qualifying facility's protection and control equipment to the satisfaction of utility representatives.

3927. Disconnection of a Qualifying Facility.

- (a) If a utility determines that a qualifying facility has not complied with its maintenance schedule, that a qualifying facility's protective equipment is not operating properly, or that a qualifying facility has been reselling the utility's energy or capacity to the utility, the utility may disconnect the qualifying facility without notice or may give the qualifying facility up to 30 days' notice of disconnection.
- (b) A notice of disconnection shall inform the qualifying facility of the maintenance to be performed, the operational practices to be modified or terminated, or the repairs to be made to protective equipment to prevent disconnection. To avoid disconnection, the qualifying facility shall comply with all requirements prior to the date of the proposed disconnection. The qualifying facility shall notify the utility when it has complied, at which time the utility shall re-inspect the qualifying facility. If the utility determines that the qualifying facility has complied, the qualifying facility shall not be disconnected. If the utility determines that the qualifying facility has not complied, the qualifying facility shall be disconnected as provided in the notice of disconnection.
- (c) A utility and a qualifying facility may agree to a reasonable continuance of a disconnection, or to a reconnection where the qualifying facility has been disconnected, if the utility believes that the qualifying facility is making a bona fide effort to comply. If the qualifying facility has been

disconnected for reselling the utility's energy and/or capacity to the utility, the agreement shall be conditioned on the qualifying facility's paying the utility for the resold energy and/or capacity.

3928. Qualifying Facility to File Generation Schedule.

A qualifying facility shall provide a utility with a proposed schedule of generation prior to interconnection. The schedule may be used by the utility to coordinate normal maintenance of its distribution facilities, to coordinate its bulk power supplies, or to coordinate regular operations for the safety of maintenance personnel.

3929. – 3949. [Reserved]

3950. Indemnification and Insurance.

- (a) A utility shall indemnify a qualifying facility against all loss, damage, expense, and liability to third persons for injury or death caused by the utility's ownership, construction, operation, maintenance, or failure of its facilities used in the interconnected operations. The utility, at the request of the qualifying facility, shall defend any suit asserting a claim covered by its indemnification. The utility shall pay all costs incurred by the qualifying facility to enforce this indemnification.
- (b) A qualifying facility shall indemnify a utility against all loss, damage, expense, and liability to third persons for injury or death caused by the qualifying facility's ownership, construction, maintenance, or failure of its facilities used in the interconnected operations. The qualifying facility, at the request of the utility, shall defend any suit asserting a claim covered by its indemnification. The qualifying facility shall pay all costs incurred by the utility to enforce this indemnification.
- (c) Absent a written agreement to the contrary, a utility and a qualifying facility shall hold each other harmless from liability for all damages caused to the facilities of the other party by reason of the improper or faulty operation of, or non-operation of, their facilities.
- (d) A qualifying facility shall obtain liability insurance in an amount the utility determines to be reasonably adequate to protect the public and the utility against damages caused by the interconnected operations. Prior to interconnection, the qualifying facility shall provide the utility with a current, valid certificate of insurance naming the utility as a beneficiary. A utility may waive the right to be named as an additional insured.

3951. Discontinuance of Sales or Purchases During System Emergencies, and Notice.

- (a) A qualifying facility shall provide energy or capacity to a utility during a system emergency on the utility's system to the extent required by 18 C.F.R. § 292.307.
- (b) Unless waived by the utility, a qualifying facility which discontinues sales to or purchases from a utility due to a system emergency:
 - (I) Shall make a reasonable effort to notify the utility by telephone prior to discontinuance. If the qualifying facility is unable to give prior telephone notice to the utility, the qualifying facility shall notify the utility by telephone no later than two hours after the termination of

the emergency. No utility shall be entitled to telephone notification under this rule unless it provides its current telephone number to the qualifying facility.

- (II) Shall give written notice to the utility no later than five days after the termination of the emergency causing the discontinuance. The written notice shall describe the emergency, the duration of the emergency, and the reasons for the discontinuance.
- (c) During a system emergency, a utility may discontinue purchases from a qualifying facility as provided in 18 C.F.R. § 292.307. Unless waived by the qualifying facility, a utility which discontinues purchases from or sales to a qualifying facility due to a system emergency shall give written notice to the qualifying facility no later than ten days after termination of the emergency causing the discontinuance. The written notice shall describe the emergency, the duration of the system emergency, and the reasons for the discontinuance.
- (d) As used in this rule, "system emergency" means a condition on a utility's system that is likely to result in imminent and significant disruption of service to customers or that is likely imminently to endanger life or property.

3952. Other Discontinuances.

Within ten days prior to any type of temporary discontinuance of purchases or sales other than one due to a system emergency, the utility or the qualifying facility shall notify the other party, except that this notification shall not be required if the parties previously have agreed upon the discontinuance or if the discontinuance is less than 15 minutes in duration.

3953. Exemption of Qualifying Facilities From Certain Colorado Laws and Regulations.

- (a) A qualifying facility shall be exempt from Colorado law and regulations as provided in 18 C.F.R. § 292.602(c), except that a qualifying facility shall not be exempt from rules 3900 through 3954.
- (b) The exemption provided for in 18 C.F.R. § 292.602(c) shall not divest the Commission of the authority to review contracts for purchases and sales of power and energy under §§ 201 and 210 of the Public Utility Regulatory Policies Act of 1978.

3954. – 3999. [Reserved]

GLOSSARY OF ACRONYMS

CAAM –	Cost Allocation and Assignment Manual
CCR –	Colorado Code of Regulations
C.F.R. –	Code of Federal Regulations
CPCN -	Certificate of Public Convenience and Necessity
CRCP –	Colorado Rules of Civil Procedure
C.R.S. -	Colorado Revised Statutes
EAO –	Energy Assistance Organization
e-mail -	Electronic mail
FERC –	Federal Energy Regulatory Commission
FDC -	Fully Distributed Cost
GAAP -	Generally Accepted Accounting Principles
HZ –	Hertz (cycles per second)

IEEE –	the Institute of Electrical and Electronics Engineers
IPP –	Independent Power Producer
KW –	KiloWatt (1 KW = 1,000 Watts)
kWh –	Kilowatt-hour
MMO –	Master Meter Operator
MW –	MegaWatt (1 MW = 1,000 KiloWatts)
MWH –	MegaWatt-hour
OCC –	Colorado Office of Consumer Counsel
RUS –	Rural Utilities Service of the United States Department of Agriculture
USOA –	Uniform System of Accounts

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
1333 H STREET, N.W., SUITE 200, WEST TOWER
WASHINGTON, D.C. 20005

ORDER

April 27, 2005

FORMAL CASE NO. 1002, IN THE MATTER OF THE JOINT APPLICATION
OF PEPCO AND THE NEW RC INC. FOR AUTHORIZATION AND
APPROVAL OF MERGER TRANSACTION

FORMAL CASE NO. 982, IN THE MATTER OF THE INVESTIGATION OF
POTOMAC ELECTRIC POWER COMPANY REGARDING INTERRUPTION
TO ELECTRIC ENERGY SERVICE, ORDER NO. 13565

I. INTRODUCTION

1. By this Order, the Public Service Commission of the District of Columbia ("Commission") adopts, on an interim basis, the Customer Service and Reliability Standards Report of the Productivity Improvement Working Group ("PIWG").¹

II. BACKGROUND

2. On May 11, 2001, the Potomac Electric Power Company ("Pepco") and New RC, Inc. ("New RC") (collectively, "Applicants") filed with the Commission a Joint Application for the Commission's approval of the proposed merger of two wholly-owned, newly-formed subsidiaries of New RC with and into Pepco and Conectiv, such that both Pepco and Conectiv would become wholly-owned subsidiaries of New RC.² The Applicants asserted, among other things, that the proposed merger would benefit Pepco's customers in the District by enabling Pepco to maintain and enhance customer service and reliability.³

3. On February 27, 2002, following the conclusion of a three-day hearing and the filing of post-hearing briefs by the parties in this proceeding, a "Unanimous Agreement of Stipulation and Full Settlement" ("Settlement Agreement") was filed with

¹ *Formal Case No. 1002, In the Matter of the Joint Application of Pepco and The New RC, Inc. for Authorization and Approval of Merger Transaction ("F.C. 1002")*, Customer Service and Reliability Standards Report of the Productivity Improvement Working Group in Response to Commission Order No. 12395 ("PIWG Report"), filed June 4, 2003.

² *F.C. 1002, Joint Application of Potomac Electric Power Company and New RC, Inc. For Authorization And Approval of Merger Transaction ("Joint Application")*, filed May 11, 2001.

³ Joint Application at 7.

the Commission.⁴ In addition to the benefits identified in the Joint Application, the Settlement Agreement proposed further benefits to the District and to Pepco's customers in the District, including the PIWG's consideration of the development of any appropriate service quality guarantee and reliability programs for Pepco.

4. By Order No. 12395, the Commission approved the proposed Settlement Agreement and, thus, the merger proposed by the Applicants.⁵ Among other things, the Commission directed Pepco to submit the customer service and reliability guarantees enumerated in the Joint Application to the PIWG for that Group's consideration, and to include the results of that Group's consideration in its Productivity Improvement Plan.⁶ In response to the Commission's directive, on June 4, 2003, Pepco filed the PIWG Report.

5. On August 15, 2003, the Commission invited interested parties to comment on the PIWG Report.⁷ However, no comments were filed. Because the PIWG Report concerned issues germane to the issues under consideration in Formal Case No. 982, the Commission again invited interested parties to submit comments on the PIWG Report.⁸ No comments were filed.

III. DISCUSSION

6. We have reviewed the Customer Service and Reliability Standards ("CSRS") and find that adopting them is in the public interest. However, we note that the PIWG is also currently in the process of reviewing Pepco's Reporting Standards as part of Formal Case No. 982 and developing a Storm Restoration Performance Standards Report.⁹ Because the standards developed in Formal Case No. 982 may have some bearing on the CSRS in this case, we have decided to adopt the CSRS on an interim basis subject to a recommendation from the PIWG on whether, and to what extent, the CSRS in this case can be merged with the Reporting Standards in Formal Case No. 982.

⁴ *F.C. 1002, Joint Motion for Approval of Unanimous Agreement of Stipulation and Full Settlement ("Settlement Agreement")*, filed February 27, 2002. The parties to the Settlement Agreement were Pepco, Pepco Holdings, Inc. (formerly New RC, Inc.), the Office of the People's Counsel, the Apartment and Office Building Association of Metropolitan Washington, the United States General Services Administration, the Washington Metropolitan Area Transit Authority, the International Brotherhood of Electric Workers - Local 1900, and AES NewEnergy, Inc. Two parties to this proceeding, the District of Columbia Government and Washington Gas Light Company did not oppose, but were not signatories to, the Settlement Agreement.

⁵ *F.C. 1002, Order No. 12395, rel. May 1, 2002.*

⁶ *Id.* at 59-60.

⁷ 50 D.C. Reg. 6817 (August 15, 2003).

⁸ *Formal Case No. 982, In the Matter of the Investigation of Potomac Electric Power Company Regarding Interruption to Electric Energy Service ("F.C. 982")*, Order No. 13054, rel. January 29, 2004.

⁹ *See F.C. 982, Order No. 13381, rel. September 15, 2004.*

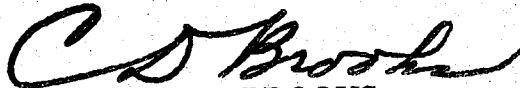
THEREFORE, IT IS ORDERED THAT:

7. The Customer Service and Reliability Standards, filed by the Productivity Improvement Working Group on June 4, 2003, are hereby adopted on the interim basis.

A TRUE COPY:

BY DIRECTION OF THE COMMISSION:

CHIEF CLERK


CHRISTINE D. BROOKS
COMMISSION SECRETARY

1002-E-116



Potomac Electric Power Company

701 Ninth Street, NW
Suite 1100, 10th Floor
Washington, DC 20068

Paul H. Harrington
Associate General Counsel

202 872-2890
202 331-6767 Fax

June 4, 2003

Mr. Sanford M. Speight
Acting Commission Secretary
Public Service Commission
of the District of Columbia
1333 H Street, N.W.
2nd Floor West Tower
Washington, D.C. 20005

03 JUN 11 PM 2:28

Re: Formal Case No. 1002

Dear Mr. Speight:

Enclosed for filing in the above matter are the original and fifteen (15) copies of the Customer Service And Reliability Standards Report Of The Productivity Improvement Working Group In Response To Commission Order No. 12395.

Very truly yours,

A handwritten signature in dark ink, appearing to read "Paul H. Harrington", is written over a horizontal line.

Paul H. Harrington

PHH/sar

Enclosure

cc: All Parties in Formal Case No. 1002

1002-E-116

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF

The Joint Application of Pepco
And The New RC, Inc. for
Authorization and Approval of
Merger Transaction

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Formal Case No.1002

CUSTOMER SERVICE AND RELIABILITY STANDARDS
REPORT OF THE
PRODUCTIVITY IMPROVEMENT WORKING GROUP
IN RESPONSE TO COMMISSION ORDER NO. 12395

In its Order No. 12395, issued on May 1, 2002 in Formal Case No. 1002, the Commission directed the Potomac Electric Power Company (Pepco) to submit to the Productivity Improvement Working Group (PIWG) within 30 days the customer service and reliability standards (Standards) enumerated in its Merger Application, and to include the results of such consideration in its Productivity Improvement Plan (PIP) (Directive 10, Order No. 12395 at 59-60). This report lists the activities conducted and the results achieved by the PIWG in complying with Directive 10. In submitting this report, Pepco is authorized to represent that the Members of the PIWG, and the International Brotherhood of Electric Workers (IBEW) -

Local 1900 are in agreement with the content of this report. IBEW Local 1900 was authorized to participate in the PIWG discussions of the Standards by Order No. 12596, issued November 7, 2002).

On May 16, 2002, Pepco presented to the PIWG the list of customer service and reliability guarantees introduced by the Company in testimony presented in its merger application in Formal Case No. 1002. At the August 8, 2002 and October 11, 2002 meetings of the PIWG, members discussed the Company's recommended changes to the original proposal and reached general agreement on a list of measures, and their specific details and implementation provisions, to be included in the list of Standards. The revised draft Standards were again discussed at the February 10, 2003, April 17, 2003, and June 3, 2003 meetings of the PIWG.

The Standards consist of two customer service and three reliability measures to be reported in the PIP, filed annually on February 15. These measures include: Customer Service - 1) Call Center Service Level and 2) Abandoned Calls; and for Reliability - 1) Worst Performing Circuits, 2) Prompt Restoration and 3) Reporting Indices of System Average Interruption Frequency Index (SAIFI), Customer

Average Interruption Index (CAIDI), and System Average Interruption Duration Index (SAIDI). The Standards, as agreed upon and proposed by the PIWG and IBEW are presented in Enclosure A. Development of the reliability standard for setting distribution system outage performance benchmarks is the most complex and is discussed in more detail below.

Distribution System Outage Performance Benchmark

Regarding the development of the distribution system outage performance benchmark, there are a number of issues to be addressed - 1) treatment of the variability of system performance from year to year due to varying weather conditions and other expected causes, such as downed trees or limbs, animals, routine equipment failures, etc.; 2) normalization of data to account for unusual events such as major storms; and 3) most recently, a major change in the method used for the collection and processing of outage information. In November 2002, Pepco implemented a new Outage Management System (OMS) which will have the effect of improving the quality of outage data collection. Improved outage identification will inherently lead to increased outage performance index values.

Varying System Performance from Year to Year

Currently, over half of the state commissions¹ have adopted formal distribution system reliability reporting requirements to monitor utility performance. Many utility commissions are now, or are in the process of, monitoring electric distribution system performance by analyzing the frequency and duration of the overall system and of the individual circuits comprising the system.

The most commonly used measures by both the commissions and the utilities are SAIDI, SAIFI and CAIDI. Standardization of distribution system performance indices has been achieved through the use of the IEEE Trial-Use Guide 1366-1998, or the more current IEEE Full-Use Guide 1366-2001.

Distribution systems are subject to the effects of weather and other conditions such as downed trees or limbs, animals, accidents, routine equipment failures, etc. There is therefore a recognized year to year variability in the resultant calculations used to measure system performance. In setting benchmarks to assess system performance, many utilities and/or their regulatory commissions use statistical methods to develop a range(s)

¹ Enclosure B, IEEE Working Group on System Design, Classification of Major Event Days (Draft) at 1.

of values to assign acceptable performance. A popular method currently being used to set benchmark limits is the standard deviation method. The standard deviation is a well-established statistical measure of variability. Both the mean and standard deviation are considered descriptive statistics. They are typically used to describe or summarize two characteristics of a large data set. The characteristics are the central tendency or middle point of the data or scores (mean/average), and the variability of the scores in the data set. Variability can be viewed as how spread out from the average or mean the scores are in a data set. For a theoretical distribution of scores that, when plotted, form a normal bell-shaped curve, two standard deviations above and below the mean will encompass about 95% of the scores in the distribution. About 5% of the scores (the extreme high and low scores) will be outside the two standard deviation band.

The PIWG and IBEW propose that reliability limits for SAIFI and CAIDI be set at the upper limit of the benchmark plus two standard deviations, which is the method recently adopted by the Pennsylvania Public Utility Commission in Docket No. D-02SPS021, Order dated August 29, 2002. New Jersey is also using the two standard deviation

approach to set the upper limit of the reliability indices benchmark.

Major Event Normalization

In order to analyze performance trends of distribution systems from year to year, utilities and commissions alike recognize the need to remove unusual events from the outage data base. For reporting of SAIDI, SAIFI and CAIDI, the Commission currently recognizes as its definition of "major event" the older IEEE definition of 10% of a utility's customers without service for a period exceeding 24 hours. This can be seen in the reporting of Pepco's performance indices in the PIP, filed annually with the Commission.²

IEEE's Working Group on System Design and the Task Force on Distribution Reliability have recently devoted a significant amount of time to refining the definition of "major event," and have recently adopted the use of the so-called "Beta Method" for identifying major events, or "outliers" from what is considered normal system operation. The Working Group, which has recently published

² Section 3, page 14 of 2003 PIP Indices provided with and without major events included. For District of Columbia customer outage reporting purposes, major outages are defined as interruptions of 10,000 or more customers for a duration of at least 24 hours. Refer to Order No. 12574 in Formal Case No. 982.

a white paper that "explores the basis, need, and benefit from normalizing reliability performance relative to major events," and that describes the Beta Method, consists of representatives from the electric industry, state utility commissions, universities, the Electric Power Research Institute (EPRI), manufacturers and engineering companies. A copy of the white paper is provided as Enclosure B.

The PIWG and IBEW recommend a change in the definition which the Commission uses to determine "major event" to the newly developed Beta Method embraced by the IEEE. This proposal uses the 2.5 Beta Method. Results of the application of the 2.5 Beta Method are presented in Enclosure C.

Data Collection and Processing

Another major concern affecting the calculation of reliability indices involves the comparison of results from annual outage records of varying accuracy. Specifically, collection of outage data has improved over the past several years and is expected to improve significantly with the implementation of the new automated

outage management systems (commonly referred to as OMS). As previously stated, Pepco has recently (November 2002) converted to an OMS. In referring to the impact of newly implemented outage management systems on page two of its *Overview of 1366-2001 the Full Use Guide on Electric Power Distribution Reliability Indices* (see Enclosure D), IEEE notes that "[s]urveys have been performed that show most utilities experience a 25% to 75% increase in their reliability indices the year after they automate their systems. This translates to a perceived degradation in service that is really a collection anomaly. The increased indices come from a more accurate customer count for both customers served as well as customers interrupted."

A five-year rolling average using OMS data is proposed for the purpose of establishing reporting limits for system performance and for calculating excludable events under the benchmark. However, because OMS was just implemented on the Pepco system in November 2002, the PIWG and IBEW are proposing a transition plan which uses three full years (2003 through 2005) of OMS data. This will allow the Company to establish annual reliability benchmarks beginning in 2006. An additional year will then be added to the calculation in 2007 and again in 2008. After the first

five years of OMS data are incorporated into the annual benchmark calculation, the annual benchmark will be calculated based on a rolling five years of OMS data. In the interim, the PIWG will investigate the feasibility of establishing an interim performance measure.

Another issue associated with the use of distribution performance indices involves the treatment of so-called momentary outages. Momentary interruptions are split-second interruptions in service and are normally excluded from the SAIFI, SAIDI and CAIDI performance indices used to define distribution system performance. Momentary outages are a normal, unavoidable part of power delivery systems that have always occurred. Today's sophisticated computers and other electronic equipment are super sensitive, however, and can be affected by a momentary that lasts only one eight-thousandth of a second. Historically, the industry has defined a momentary outage as one which is less than one minute in duration. However, manual or automated sensing and diagnostic systems and equipment can often be employed for slightly greater than one minute to lockout and redirect power flows. That is why there is a move in the industry to redefine a momentary outage to a duration of five minutes or less. At page 2 of

its *Draft Full-Use Guide for Electric Power Distribution Reliability Indices* (IEEE P-1366/D10), dated January 2003, IEEE's Working Group on System Design recommends adoption of a revised definition of momentary event to incorporate the five minute standard as follows:

3.1.9 Interruption, momentary event.

An interruption of duration limited to the period required to restore service by an interrupting device. Note: Such switching operations must be completed within a specified time of 5 minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. For example, if a recloser or breaker operates two, three, or four times and then holds (within 5 minutes of the first operation), those momentary interruptions shall be considered one momentary interruption

PEPCO has recently adopted the new five-minute industry standard for measuring momentary interruptions and the PIWG and IBEW recommend the Commission adopt this standard for reporting purposes. For comparative purposes, 2001 SAIDI and SAIFI performance indices were calculated using a 1 minute and a 5 minute sustained outage threshold. SAIDI changed imperceptibly and SAIFI changed by 6% from 1.09 (1 minute) to 1.02 (5 minutes).

It is important to emphasize that the change in the definition of momentary interruption from one minute to five minutes affects only the calculation of performance

indices and will have absolutely no effect on restoration times of electric service to the customer or on the ability of the customer's equipment to operate.

District of Columbia Standards – Proposed Pepco Reliability and Customer Service Standards			
Performance Measure	Description	Benchmark	Details / Comments
SAIFI, CAIDI, & SAIDI	Maintain minimum service interruption indexes.	2 standard deviations above historical Outage Management System (OMS) average Baseline values (excluding major event days as defined in the paper prepared by the Major Event Days' IEEE's Working Group on System Design)	Continue current requirements provided in annual PIP, to report annual reliability indices of SAIFI, CAIDI and SAIDI (with and without major events) by Feb. 15 of the following year. Establish benchmark procedure. Calculate & Report Benchmark Values by:
	Failure to meet Benchmark triggers Corrective Action Plan		<ul style="list-style-type: none"> - Assembling three full years (2003 -- 2005) of OMS data for 2006 Benchmarking, - Excluding Major Event Days using IEEE proposed 2.5 Beta Method, - Incorporating an additional year of OMS data annually until 5 years of OMS data are incorporated in the program. Thereafter, the benchmark will be reset annually using a rolling five year average, - Determining Benchmark by calculating 2 standard deviations from Baseline.
			<p>if the Company fails to meet this standard, it will be required to develop a corrective action plan which will:</p> <ul style="list-style-type: none"> - describe the cause(s) of deterioration in performance; - describe the corrective measures to be taken to address identified issues; and - set a target date for completion of the corrective measures. <p>Progress on current corrective action plan will be included in an annual PIP report submitted to the Commission.</p>
Individual Circuits	Identify and analyze poor performing circuits – Improve lowest 2%. Failure to improve performance will trigger Corrective Action Plan	Individual feeder Performance determined using: Composite Performance Index (CPI)	<p>Continue current annual (Feb. 15) PIP reporting of worst performing 2% of feeders (Utility methodology) and corrective actions planned, corrective action taken (year 1) and subsequent performance (year 2).</p> <p>Corrective action plan – For those feeders not showing improvement, provide an explanation for why a particular circuit has remained on the list for more than two years, how the problem will be addressed and a proposed schedule for taking action. Progress on the corrective action plan will be included in the annual report submitted to the Commission.</p>

District of Columbia Standards -- Proposed Pepco Reliability and Customer Service Standards			
Performance Measure	Description	Benchmark	Details / Comments
Prompt Restoration	Restore Service Promptly	Complete Restoration within 24 hours	<p>Include in annual (Feb. 15) PIP report on reliability data outlining the percentage of customer outages that extend beyond 24 hours and the typical causes for these extended outages. Due to implementation of OMS system, historical data cannot be used to evaluate this activity.</p> <p>Statistics for Major Events are excluded: Pepco proposed reporting requirements of November 1, 2000, submitted in response to Order No. 11604 in Formal Case No. 982, specify that within three weeks of major outage, written reports containing detailed statistics on customer outages will be filed. The Commission approved this reporting requirement in Order No. 12574, issued October 22, 2002.</p>
Call Center Service Level	Answer calls Promptly	Answer 70% of calls within 30 seconds	<p>Included in annual (Feb. 15) PIP report the actual performance obtained during the reporting period as measured by Pepco. Measurements for calls promptly answered are taken from the time the customer selects a menu option and is placed in the queue until the call is answered. Abandonment rate will be defined as the annual percentage of calls abandoned after the customer selects a menu option to speak to a customer service representative, in other words when they are in-queue.</p> <p>Statistics exclude calls made during periods of major telecommunication failures and periods of labor disruption.</p> <p>If the Company fails to meet this standard, it will be required to develop a corrective action plan. The corrective action plan will:</p> <ul style="list-style-type: none"> - describe the cause(s) of the non-compliance; - describe the corrective measures to be taken to ensure that the particular standard is met or exceeded in the future; and - set a target date for completion of the corrective measures. <p>Progress on current corrective action plans will be included in the annual PIP report.</p>
Abandoned Calls	Minimize call abandonment	Maintain Abandoned call Level below 10%	

Classification of Major Event Days

Working Group on System Design

Abstract— A paper that explores the basis, need, and benefit of classifying reliability performance relative to major events. Today, many internal and external goals are set based on reliability performance. Internal as well as external comparison is difficult to make due to variations in weather, collection methods, and a plethora of other variables. The Working Group on System Design has developed a statistics based methodology that classifies reliability data into normal and major event days. After classification, analysis can be performed on each data set using separate processes to arrive at sound business decisions and to make internal comparisons possible. This paper describes the newly developed methodology, the "Beta Method".

Index Terms— Distribution Reliability, Major Event Day, 2.5 Beta Methodology, log normal statistical approach, Storms.

I. INTRODUCTION

Deregulation and re-regulation have led electric utility regulators and customers alike to scrutinize the electric power industry. Claims of improved service for less cost have been used to foster deregulation. Regulators have tried to ensure a continuation, and in some cases, an improvement in electric service reliability under the new operating environment. Electric utility executives have endeavored to continue to maintain service levels without increasing cost, and in some cases, by decreasing expenditures. As a result both internal and external goals have been set around reliability performance, yet there has been no uniform methodology for removing events that are so far away from normal performance that they are known as outliers. Without removal of such events, the variation in annual performance is too great to set meaningful targets. This paper discusses the need to classify reliability performance. Normalizing reliability data will reduce the variability, thus making trending/goal setting possible. It will also segment performance during large-scale events so that appropriate post analysis can be performed.

Distribution re-regulation has been sweeping the country as evidenced¹ by Figure 1.

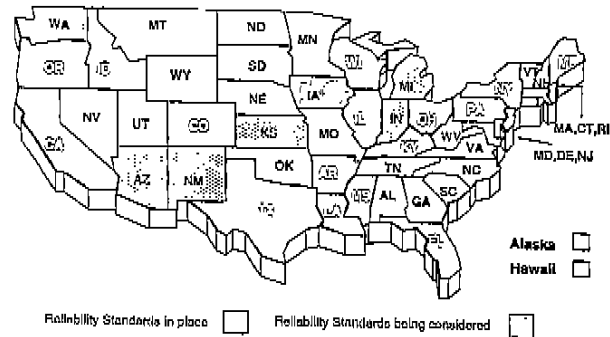


Figure 1. US States involved with distribution reliability regulation.

A few short years ago, only a hand full of states had formal distribution reliability reporting requirements. Today, the number has grown to over half of all US states and is continuing to rise. Extensive reporting requirements have been initiated by some regulators, as evidenced by the Illinois Commerce Commission ("ICC") requirements, where utilities are required to file an annual report that is often over 100 pages long. Many regulators review not only annual statistics, but also lists of worst performing circuits, reliability expenditures and a variety of other detailed data items. Some states have extended regulatory boundaries to require utilities to purchase outage management systems ("OMS"). It is clear, that executives and regulators alike require a reasonable method for tracking and reporting reliability performance, a method that provides information for proper decision-making.

The IEEE Working Group on System Design, the group that authored the *Full-Use Guide on Electric Power Distribution Reliability Indices-1366-2001*, has recently developed a statistics based methodology (herein referred to as the "Beta Method") for identifying outlying performance (otherwise known as Major Event Days or MEDs). The method is known as the Beta Method because of its dependence on log normal distribution (the distribution that best describes reliability performance data) where beta is a key parameter. Beta, in this case, does not indicate a test-phase that will be finalized at some later date. Using the Beta Method, utilities can calculate indices on both a normalized and unadjusted basis (identifies abnormal performance). Appropriate decision-making can be performed on each set of indices. Normalized indices provide metrics that can, and should, be used for both

¹ This paper was produced by the Working Group on System Design. Please see the last section of the paper for group membership.
² "Reliability on the Regulatory Horizon" by Cheryl A. Warren and Michael J. Adams, Presented by Charlie Williams at the IEEE T&D Conference in Atlanta 2001.

internal and external goal setting. Unadjusted indices, when compared to the normalized indices, provide information about utility performance during major events. Events that may be included in unadjusted information are major weather events, major substation events, or unexpected catastrophic events such as earthquakes. Major events are events that are beyond the design and/or operational limits of a utility. It is anticipated that both executives and regulators will scrutinize those events that cause MEDs and take appropriate action to mitigate their future impact on reliability. There could be cases where no additional action is required, as would be the case when an event was beyond control of the utility (e.g., Class 4 hurricane).

II. METHODOLOGY DEVELOPMENT

The Working Group is comprised of over 100 active members from thirty-one states and six countries that hail from universities, utilities, regulatory agencies and consultancies. The Working Group has spent the last two years creating a methodology that would:

- Be fair to all utilities regardless of size,
- Allow segmentation of reliability data into normal and abnormal categories, based on the identification of outlier events that cause Major Event Days,
- Allow use of normalized indices for internal and external goal setting,
- Be consistent for various amounts of data availability and for all utilities, and
- Be easy to understand and execute.

Many working group members anonymously donated their outage data for methodology development. A volunteer contingent of members from the working group performed rigorous analysis of all provided data while evaluating the efficacy of a number of proposed methods. Before the final methodology was chosen, several other methods were developed and abandoned due to their inability to meet the criteria noted above. Rich Christie authored "*Statistical Classification of Major Reliability Event Days in Distribution Systems*", a paper that describes some of the thinking. The working group has selected the Beta Method as the method best meeting the criteria.

III. THE BETA METHOD

The method is easily applied to reliability data and can be set up to run automatically from an OMS, or be manually applied by using MS Excel™ and/or MS Access™. Its purpose is to allow major events to be studied separately from reliability performance that occurs during what would be considered normal operation, and, to better reveal trends in normal operation that would be hidden by the large statistical effect of major events.

The Beta Method is used to identify major event days. A major event day is a day in which daily SAIDI exceeds a threshold value T_{MED} .

In calculating daily SAIDI, interruption durations that extend into subsequent days accrue to the day on which the interruption begins. This technique simplifies calculations.

The major event day identification threshold value T_{MED} is calculated at the end of each reporting period for use during the next reporting period. For utilities that have six years of reliability data, the first five are used to determine T_{MED} and that threshold is applied during the sixth year. The methodology follows:

1. Values of daily SAIDI for a number of sequential years, ending on the last day of the last complete reporting period, are collected. Consistency of future results is enhanced if five or six years of data are used, but, if fewer than five years of historical data are available, all of the available complete year, historical data should be used. Use of more than six years of data may distort the effects of major events and minimize the impact of the analysis.
2. Replace any day in the data set that has a value of zero for SAIDI with the lowest non-zero SAIDI value in the data set. (This permits the calculation of the logarithm of a SAIDI value for every day. While not technically precise, this does enhance the overall accuracy and consistency of the method.)
3. The natural logarithm (\ln) of each daily SAIDI value in the data set is calculated.
4. The average of the logarithms, α (Alpha), (also known as the log-average) of the data set is calculated.
5. The standard deviation of the logarithms, β (Beta), (also known as the log-standard deviation) of the data set is calculated.
6. The major event day threshold, T_{MED} , is calculated by using the equation:

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$
 (Note that this value should in theory give, on average, 2.3 major event days per year. In practice, using the donated utility data, higher numbers of major event days per year, from two to eight, are seen. This is not unexpected since the actual data does not conform precisely to the log-normal distribution.)
7. Any day with daily SAIDI greater than the threshold value T_{MED} that occurs during the subsequent reporting period is designated a major event day. The data for this

day should be removed when calculating normal reliability performance.

It is the group's recommendation that major event day performance be reviewed in a different, possibly more rigorous, manner than normal day performance.

SAIDI was chosen as the metric in order to capture the effects on customer minutes interrupted ("CMI") or duration of events. SAIDI is the division of CMI and total customers served. Dividing by total customers served allows utilities to use the methodology even after a merger has occurred. Despite the fact that SAIDI is used as the metric to determine MEDs, the methodology is applied to all indices.

Because the methodology classifies all performance into two data sets, 1) normal performance and 2) abnormal performance, it cannot favor a poorly performing utility. All data is provided in one of the two classifications. It is up to executive management and regulators to review both data sets to draw conclusions about overall performance.

IV. EXAMPLES OF THE METHODOLOGY RESULTS

For a detailed calculation example please refer to *Draft 7 of the Full-Use Guide on Electric Power Distribution Reliability Indices*. Using data provided by member utilities, two illustrative examples are presented here. Utility 4 used three years of data to determine threshold values while Utility 10 used seven years of data.

A. Example 1 - Utility 4

Figure 2 and Figure 3 show analysis results from Utility 4. The lower light blue bars show the normalized values for SAIFI and CAIDI. Utility 4 is required to report SAIFI and CAIDI, not SAIDI to their regulator. The upper orange bars show the contribution from abnormal events to SAIFI and CAIDI. The summation of the two bars is the total system SAIFI and CAIDI or unadjusted SAIFI and CAIDI. Note that normalized SAIFI performance was constant, with no more than 3% variation from year to year. The normalized CAIDI was relatively constant, with no more than an 8% variation. Unadjusted, SAIFI varied 11% from year to year and CAIDI varied between 56% and 70% over the period.

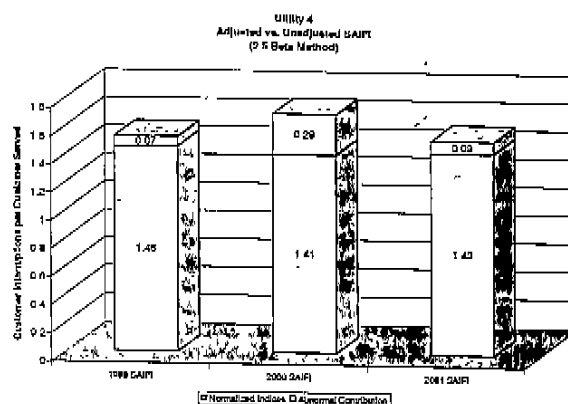


Figure 2. Utility 4 SAIFI

Figure 3 presents a clear illustration of the significance of identifying abnormal events. In evaluating the three years of data presented, it is evident that 2000 was the stormiest. For that year (2000), over 42% of the utility's overall CAIDI could be attributed to the abnormal event CAIDI. Notice that normalized CAIDI was fluctuating within a reasonable band (no more than 8% variation from year to year). It is likely that the system is performing within acceptable design and/or operational limits. The fact that major event contributions vary from year-to-year is to be expected, and may be directly correlated to weather variations. If the major event variation is due to conditions within the utility's control, then executives and regulators should take appropriate action. Furthermore, if over time there is indeed a true and sustained change in the weather patterns affecting a utility's service territory, this "normalization" process will reflect (and include) that change. If that occurs, then there are strong and supported reasons for the utility to change its operating practices.

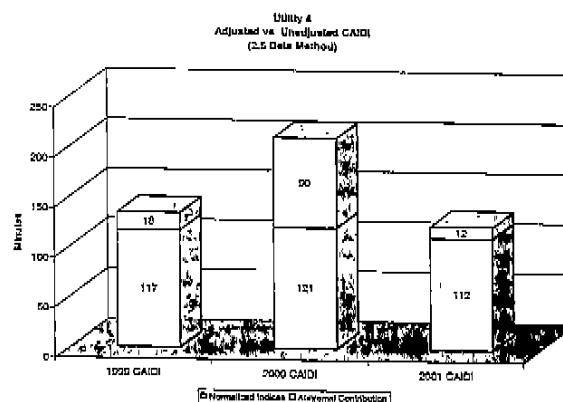


Figure 3. Utility 4 CAIDI

Figure 3 is a clear example of why normalizing indices is critical to customers, regulators and internal utility goals. If the unadjusted data were used to target spending, then this utility would likely be trying to solve non-problems (e.g., events that occurred as a result of one major storm and are unlikely to occur again in the foreseeable future). In short, they could be focused on the wrong issues and thus spend ratepayer money on sub-optimal solutions.

B. Example 2 - Utility 10

Figure 4 and Figure 5 show results from Utility 10. SAIFI, even adjusted, is still increasing at a steep rate, while CAIDI is oscillating and is fairly constant. Given this type of information, executives from this utility may alter spending and action plans if no recent IT systems changes have been implemented. If this utility recently implemented a fully connected outage management system that more accurately captures reliability information, then these graphs are explainable by that fact alone. It is well known that after fully connected IT systems are implemented, that reliability appears to worsen since more accurate information is being collected. For this example, we assume that no system changes occurred.

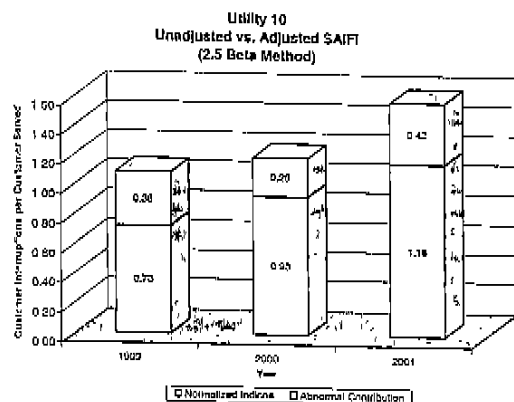


Figure 4. Utility 10 SAIFI

Unadjusted CAIDI varies as much as 69% while adjusted CAIDI varies only as much as 28% a year. While 28% is a high percentage, it is significantly better than unadjusted statistics. This information may indicate crew overload on major event days. It appears that the major events were significant enough to completely saturate crew availability and thus restoration efforts were excessively delayed.

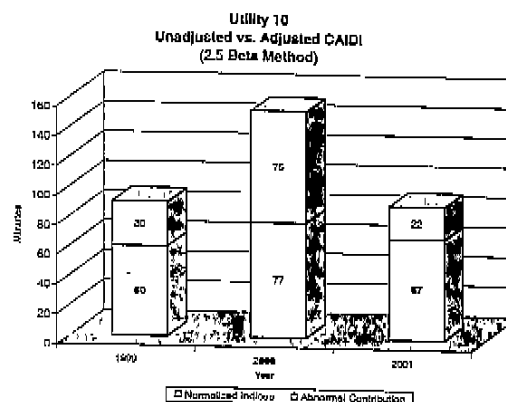


Figure 5 Utility 10 CAIDI

C. Example 3 - Worst Performing Circuits

Many state regulators are requesting reports on worst performing circuits ("WPC"). Typically, all interruption data is used to determine the WPC list. The number of circuits reported to regulators across the US varies from 4% to 10% of the total circuits on the system with each state allowing different reliability data adjustments. There are only a few states, at the present time that review circuit performance based on storm-adjusted or major event classified information. Consequently, utilities may be required to investigate solutions to problems that would only occur during a major event. This may not be the most cost-effective approach. The Beta Method will allow utilities to apply worst performing circuit criteria to adjusted data, thus identifying circuits that are most likely to remain worst performing if actions are not taken. In cases where WPC criteria is applied to all events, circuits often become members of this group due to one extreme event. Using non-classified data seems to defeat the regulatory purpose, which presumably is to solve repetitive reliability issues on problem circuits.

This paper has provided two simple examples using the Beta Methodology. Many utilities have used the methodology on their own data and determined it to be a fair methodology. It is important to remember that when using the methodology, no data is excluded, instead it is classified and analyzed using separate processes.

V. BENEFIT SUMMARY

Daily, decisions are made at utilities based on perceived risk versus anticipated reward. The Beta Method provides a mechanism to segment information into appropriate categories allowing different decision paths to occur. It is the hope of this group that classification will result in better business decision-making. Regulators, utilities, and customers benefit from the Beta Method

because it segments reliability performance to reveal trends that utilities can then address.

A large group, that represents all interested parties, created this methodology. The Beta Method allows utilities and regulators to confidently set goals/targets based on normal, and expected future performance. It also provides a technique to review performance during severe events.

VI. WORKING GROUP MEMBERS

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* Indicates participation on sub group that performed analysis and wrote text.

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Major Event Normalization

Effect of 2.5 Beta Method on Pepco System

Potomac Electric Power Company

**Asset Management
Reliability Services
(September 18, 2002)**

Prepared by:

Mostafa Hassani, P.E.

Leslie M. Pilar, (Engineering Intern)

Reference for this study:

IEEE Working Group on

Major Event Normalization

INTRODUCTION

The existing language from IEEE Standard 1366-1998, Section 3.13, defines “major event” as “a catastrophic event which exceeds reasonable design or operational limits of the electric power system during which, at least 10% of the customers within an operating area experience a sustained interruption during a 24 hour period”. A number of utilities claimed that the existing 10% method is not fair because of different weather patterns affecting their jurisdictions. They found that it was impractical to utilize IEEE indices such as SAIFI, SAIDI, CAIDI, etc., for benchmarking purposes among different utilities, and therefore, proceeded to use their own method for identifying major events. Consequently, in order to resolve this problem, an IEEE Working Group was formed to develop a fair statistical methodology acceptable to all utility members for identifying a Major Event Day (MED). A MED is a catastrophic event day that exceeds design limits of the electric power system that is characterized by:

- Extensive damage to the electric power system;
- More than a specified percentage of customers simultaneously out of service;
- Service restoration time frame longer than specified.

The IEEE Working Group is comprised of over 100 members from thirty-one states and six countries. Members are from utilities, universities, regulatory agencies and consulting firms. The group has developed the “2.5 Beta (2.5 β) Method” for identifying MEDs and is proceeding to finalize the IEEE P1366 Trial Use Guide for Electric Power Distribution Reliability Indices. On July 22 and 24, 2002, in Chicago, the Working Group members discussed the 3 β Method versus the 2.5 β Method in length. A motion was made to accept the 2.5 β Method. The Motion passed with 27 for, 5 against and 3 abstained. The committee carried the motion to adopt the 2.5 β Method for classification of MEDs. The purpose of this study is to evaluate and present the effects of the 2.5 β Method on the Pepco system.

THE BETA METHOD

The Log-normal distribution is the probability distribution where the natural logarithm of a sample values has a normal distribution. This process involves finding the values of the log normal parameters and compute a threshold in which identifies the boundary of the MED. A MED is a day on which the daily SAIDI exceeds a threshold value. The MED identification threshold value is calculated at the end of each reporting period for use during the next reporting period as follows:

- Calculate daily SAIDI, using either 5 years of outage data;
- If any day in the data set has a value of zero for SAIDI, replace them with the lowest SAIDI value in the data set;
- Calculate the natural logarithm of each SAIDI day;
- Evaluate α (Alpha), the average of the logarithms (also known as log-average of the data set);
- Evaluate β (Beta), which is the standard deviation of the logarithms (also known as the log-standard deviation of the data set);
- Compute the MED threshold (2.5 β), which is exponential $e^{(\alpha+2.5\beta)}$;
- Any day with a SAIDI value greater than the calculated threshold value, will be identified as a MED.

EFFECT OF THE BETA METHOD ON PEPCO SYSTEM

In order to evaluate the effect of the Beta Method on the indices such as SAIFI, SAIDI and CAIDI, seven and one-half years of daily outage data was extracted from the outage history (1995 through second quarter 2002). In order to calculate both 2.5 β threshold values for the years 2000, 2001, and 2002 data sets were combined as follows:

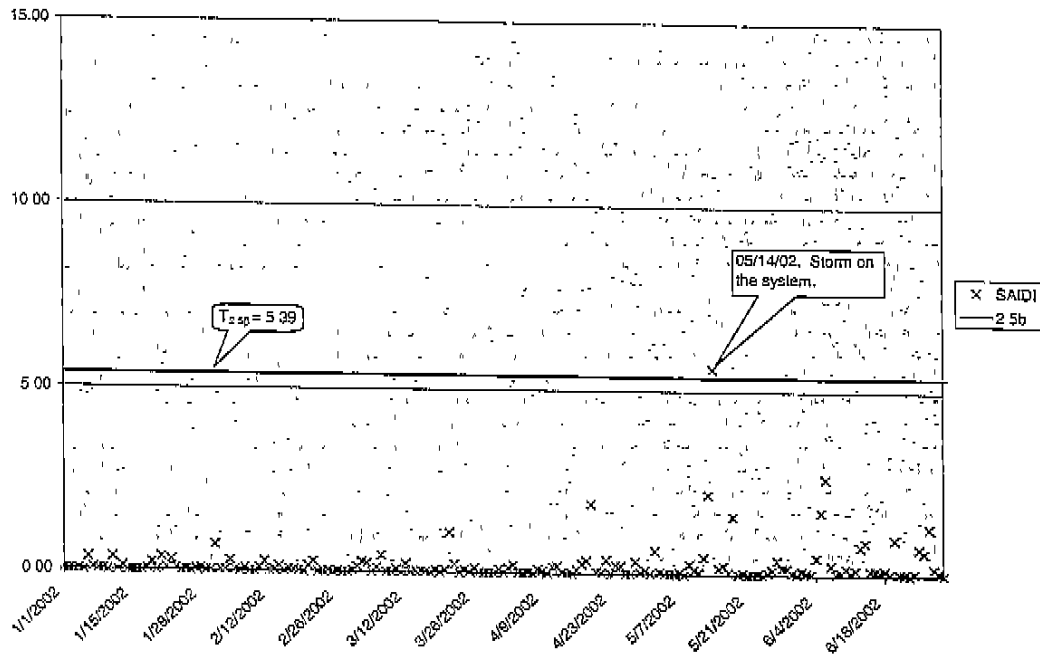
1. Five years daily data sets (1997, 1998, 1999, 2000 & 2001) were combined to evaluate 2.5 β threshold for 2002. The 2.5 β threshold value for the year 2002 is calculated to be 5.39. Refer to graph No. 1.
2. Five years daily data sets (1996, 1997, 1998, 1999 & 2000) were combined to evaluate 2.5 β threshold for 2001. The 2.5 β threshold value for the year 2001 is calculated to be 5.59. Refer to graph No. 2.
3. Five years daily data sets (1995, 1996, 1997, 1998 & 1999) were combined to evaluate 2.5 β threshold for 2000. The 2.5 β threshold value for the year 2000 is calculated to be 5.48. Refer to graph No. 3.

In order to identify the MEDs, daily SAIDI values for each of the years were calculated. Threshold point and daily SAIDI values were graphically plotted to identify the MEDs and therefore, compare them with the Major Storm Days identified using the 10% Method. Our study concluded that:

- For the year 2002, the 10% Method resulted in no Major Storm Event, while the Beta Method identified May 14 as a MED. Refer to graph No. 1. A storm was declared on the Pepco system at 2041 hours on May 13 and continued into May 14, 2002. The thunderstorms and high winds caused numerous system-wide outages affecting approximately 45,000 customers. At one point, 3-69kV, 4-34kV, 19-13kV and 4-4kv feeders were locked out events. The effect of additional MED would have reduced the SAIFI, SAIDI and CAIDI by approximately 11.54%, 14.84% and 3.82%, respectively.
- During 2001, the 10% Method resulted in no Major Storm Event, while the Beta Method identified three MEDs (June 14, August 11, and September 24). Refer to Graph No. 2. On September 24, there was a tornado in the College Park and Greenbelt area. This storm affected approximately 25,000 customers. On June 14, Operations de-energized several feeders out of Georgetown Sub. 12 due to heavy load conditions. The effect of three additional MEDs would have reduced the SAIFI, SAIDI and CAIDI by approximately 3.67%, 17.64% and 14.15%, respectively.
- During 2000, the 10% Method resulted in no Major Storm Event while the Beta Method identified two MEDs (May 13 and August 7). Refer to Graph No. 3. On both May 13 and August 7 the Pepco system was affected by severe thunderstorms. The effect of two additional MEDs would have reduced the SAIFI and SAIDI by approximately 3.67%, 23.19% and 15.32%, respectively.

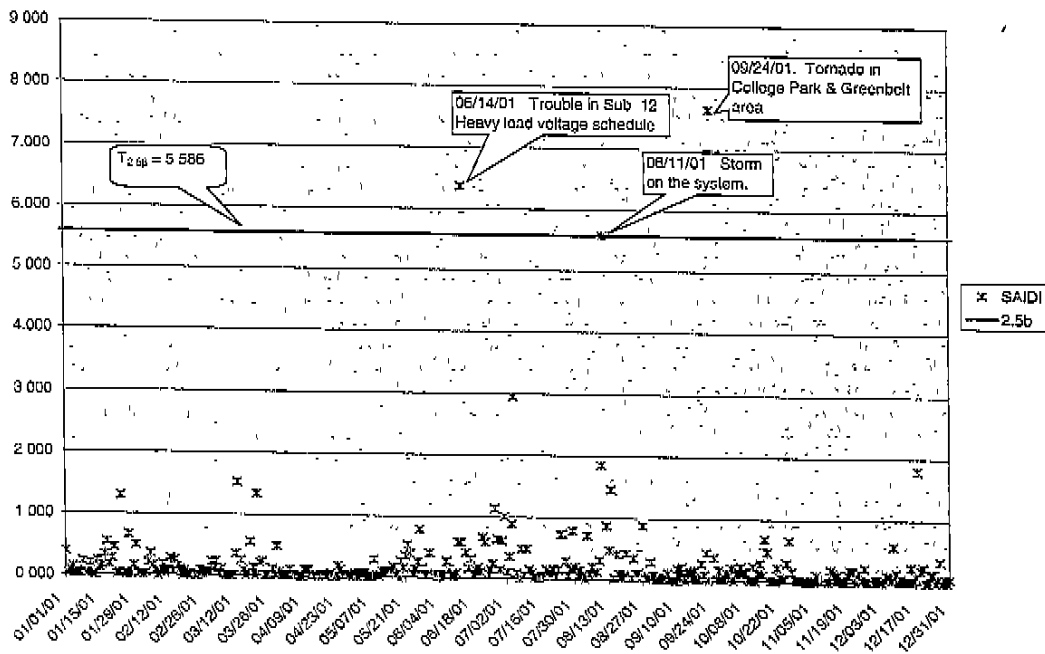
The re-calculated values for SAIFI, SAIDI and CAIDI using the 2.5 β Method are represented in Graph Nos. 4, 5, 6, and 7. Based on our analysis, utilization of the 2.5 β Method over the 10% Method resulted in some reduction of SAIFI, SAIDI and CAIDI values. The following graphs represent these analyses:

2002 Using 5-Year Data (1997 thru 2001)



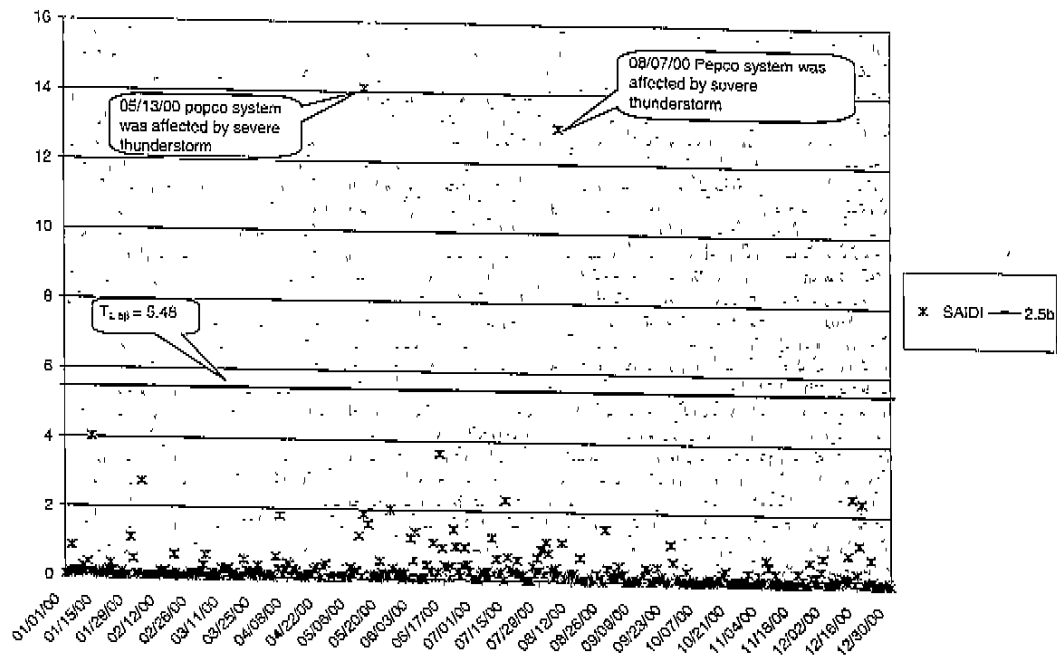
Graph No. 1. Using 5-Years of Outage Data (1997 through 2001) to identify year 2002 MED.

2001 Using 5-Year Data (1996 thru 2000)



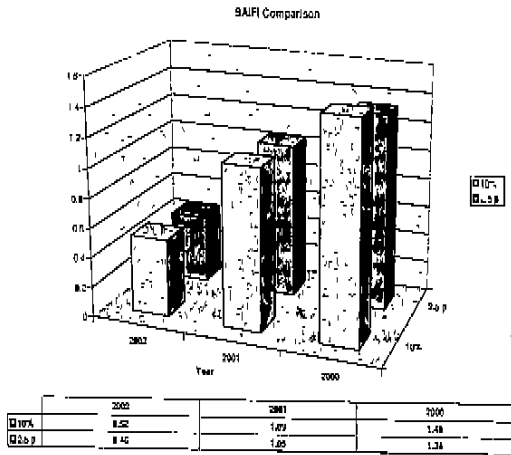
Graph No. 2. Using 5-Years of Outage Data (1996 through 2000) to identify year 2001 MEDs

2000 Using 5-year Data (1995 thru 1999)

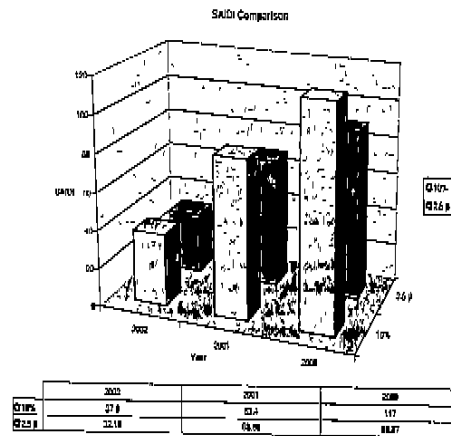


Graph No. 3 Using 5-Years of Outage Data (1995 through 1999) to identify year 2000 MEDs.

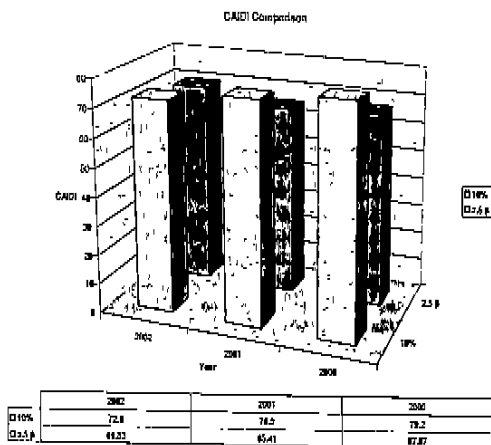
Comparing Indices Between 2.5 β And 10% Method



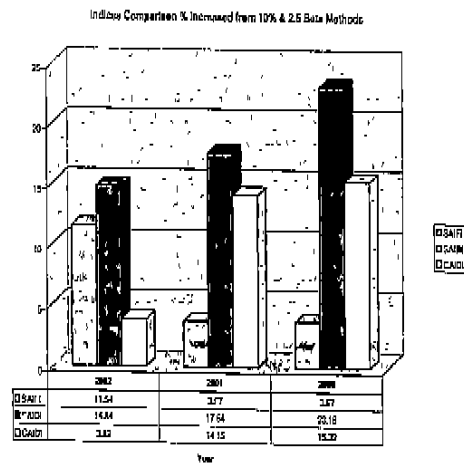
Graph No.4- SAIFI comparison between the 2.5 β & 10% Methods.



Graph No 5- SAIDI comparison between the 2.5 β & 10% Methods.



Graph No. 6- CADI comparison between the 2.5 β & 10% Methods



Graph No. 7- Percentage reduction on indices from 10% to 2.5 β Method

* For the year 2002, indices are given for the first 6 months (1/1/02 through 6/30/02)

Overview of 1366-2001 the Full Use Guide on Electric Power Distribution Reliability Indices

Cheryl A. Warren, *Senior Member, IEEE*

Abstract—The purpose of this paper is to introduce and describe the formation of 1366-2001 Full-Use Guide for Electric Power Distribution Reliability Indices. Members of the Working Group on System Design and its Task Force on Distribution Reliability Indices have been working on this project since the late 1980's. This group has grown from a few participants to 150 active members. They have written the Guide to assist utility management, public service commissions, customers, and staff engineers with understanding distribution reliability indices and the factors that affect them. In the last few years there has been a need for 1366 to become more of a benchmarking guideline with strict definitions. The WG and TF have endeavored to address this concern.

Index Terms—benchmarking, distribution reliability, major events, and storms.

I. INTRODUCTION

THIS document describes the formation of the *Full-Use Guide for Electric Power Distribution Indices* IEEE 1366-2001 ("Guide") and the Working Group and Task Forces that prepared the Guide. The Distribution Subcommittee sponsors the Working Group on System Design. The Working Group on System Design sponsors three Task Forces: 1) The Task Force on System Design, 2) The Task Force on Outage Reporting, and 3) The Task Force on Reliability Indices. This paper will focus on the activities of the Task Force on Reliability Indices ("TF"). The TF has been actively working on the creation of Guide for Electric Power Distribution Reliability Indices for many years. The Trial-Use Guide 1366-1998 was approved in March 1998 and a Full-Use Guide 1366-2001 was approved in March of 2001.

The Guide is used for trending reliability performance, setting the baseline for reliability performance as well as communicating performance to management, key customers, and regulators. There is a wide variance in reported indices between utilities. Some of the reasons for differences will be discussed in this paper.

II. MAJOR SECTIONS OF THE GUIDE

The IEEE Std. 1366-2001 contains six major sections: 1) Overview, 2) Definitions, 3) Indices, 4) Application of the Indices, 5) Factors that affect index calculation, and 6) Annex. The following subsections will describe each major section.

A. Overview

The Overview gives the scope and the purpose of the Guide. The scope is reprinted here:

"This guide identifies useful distribution reliability indices and factors that affect their calculation. It includes indices that are useful today as well as ones that may be useful in the future. The indices are intended to apply to distribution systems, substations, circuits, and defined regions"

Since its inception, the TF has worked to satisfy the stated scope. Over the last few years however, several entities have asked that language in the Guide be strengthened to make it easier to apply to benchmarking activities and to make it easier for public service commissions to use as a baseline for regulation. Today, making the definitions clearer is the main objective of the TF.

B. Definitions

There are twenty-one definitions in the Guide. The difference in interpretation of these definitions is one of the reasons that a wide variance exists between reported performance of utilities. The TF has been focusing on the definition of *Major Event* for the past year. In 1366-1998, the definition of Major Event was:

"A catastrophic event that exceeds design limits of the electric power system and that is characterized by the following (as defined by the utility):"

- a) Extensive damage to the electric power system;
 - b) More than a specified percentage of customers simultaneously out of service;
 - c) Service restoration times longer than specified.
- Some examples are extreme weather, such as a one in five year event, or earthquakes."*

In 1366-2001, the definition changed to:

"Designates a catastrophic event which exceeds

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reasonable design or operational limits of the electric power system and during which at least 10% of the customers within an operating area experience a sustained interruption during a 24 hour period."

Since that time the TF has explored methodologies created by Richard D. Christie, Charles W. Williams, and James D. Bouford that are designed to statistically identify abnormal system performance. These gentlemen have written papers for this panel session describing the statistics behind the proposed methodologies. It appears at the time of this writing that a Beta Methodology¹ will be adopted as the next Major Event definition. Please see section III. Major TF Initiatives.

The group plans to prepare documentation explaining the basis for the new statistical method. Other definitions that the TF will focus on over the next 12 months include: customer count, interruption and step-restoration.

C. Indices

This section describes distribution reliability indices including SAIFI, SAIDI, CAIDI, CTAIDI, ASAI, ASIFI, ASIDI, CEMI_n, MAIFI, and CEMSMI_n. Customer based sustained indices include: SAIFI, SAIDI, CAIDI, CTAIDI, ASAI. Load based sustained indices include: ASIFI, ASIDI. Momentary indices include CEMSMI_n, MAIFI and MAIFI_E. The newest indices are CEMI_n. Customers experiencing multiple interruptions, and CEMSMI_n. Customers experiencing multiple sustained interruptions and momentary interruptions events. Many states are now considering use of CEMI_n as a basis for performance. In Florida, they are considering using CEMI_s. If this value is exceeded, the commission is considering fines that would be paid to the customers who experienced poor performance.

D. Application of the Indices

This section shows examples of index calculation based on a fictional database. Collection of interruption data is one of the largest sources of error when reporting performance. Some utilities have very sophisticated systems that contain fully connected models. A fully connected model allows a utility to know exactly how many customers are connected, exactly where they are connected and how they relate to one another. Utilities that have a fully connected model that is integrally tied to their outage management system ("OMS") and their geographical information system ("GIS") with automated mapping and facility management systems ("AM/FM") often have the most accurate reliability indices. Surveys have been performed that show most utilities experience a 25% to 75% increase in their reliability indices the year after they automate their systems. This translates to a perceived degradation in service that is really a collection anomaly. The increased indices come from a more accurate customer count for both customers served as well as

customers interrupted.

E. Factors that Affect the Calculation of Reliability Indices

This section discusses the recommendation of exclusions from index calculation. The Guide recommends that utilities report indices two ways: 1) including everything and 2) excluding a well-defined subset of data. The typical exclusions include major events and momentary interruptions.

F. Annex

This section contains results from previous reliability surveys that the task force performed of US utilities. There is also a section on major event definitions from an EEI survey. The group plans to continue expanding this section with other pertinent information that they develop.

III. MAJOR TF INITIATIVES

The TF has been meeting at the IEEE PES winter and summer power conferences. In addition to the bi-annual meetings, the group has been meeting using an Internet based meeting application (Webex). The Internet meetings have been occurring approximately every six weeks, which has facilitated continuing standards activities. The main focus of activity has been discussion of the *Major Event* definition.

A. Major Event Definition

Many groups felt that the current definition was not adequate for comparison of indices between utilities. There was little basis for the existing 10% for 24-hour definition. The group felt strongly that the foundation of the new definition should include the following concepts:

- Create a methodology to partition data into "normal" and "abnormal" operating days,
- Suggest rigorous reporting on "abnormal" days through a separate process,
- Use the "normal" operating days for trending, goal setting, benchmarking and reporting,
- Create a definition that is easy to apply, understandable by all, and specific,
- The definition must be equitable for both large and small utilities.

A group of TF members worked diligently to create test methodologies including 1) the natural breakpoint method (James D. Bouford), the boot strap method (Richard D. Christie), 3) the distribution fit method (Richard D. Christie), 4) the three sigma method (Charles W. Williams), and 5) three beta method (James D. Bouford, Richard D. Christie, John McDaniel, Rodney Robinson, David J. Schepers, Hector Valtierra, Joe Viglietta, Cheryl A. Warren, and Charles W. Williams). Virtually all the TF members provided data and or data analysis to test the methods (please see a list of members in the acknowledgements section).

At the time of this writing, it appears that the Beta methodology will be chosen as the new method for defining major events. The steps to apply the beta method are:

1. Using five years of data (or as many as you have up to five).

¹ Please see Section III. Major TF Initiatives for explanation of the Beta Method

2. Create columns of data with date, year, CMI per day, and SAIDI per Day. Also include the customers served.
3. If there are any zero days, use the lowest value in the set for that day.
4. Order the SAIDI/Day from Highest to Lowest
5. Calculate the natural log (LN function) of each value, $\text{Ln}(\text{SAIDI/day})$
6. Calculate the mean (α) (AVERAGE function) and standard deviation (β) (STDEV function) of the natural log values.
7. Find the threshold by $e^{(\alpha + 3\beta)}$ (EXP function).
8. For the following year of data, segment the days above the threshold into the abnormal group.

The group plans to prepare power point and word presentations and papers for use in describing the new process and benefits.

B. Cause Codes

Before the major event discussion, the group was focused on adding a section to the guide on standard cause codes. This section is a work in progress. The current minimum set of causes codes include:

- Animals
- Lightning
- Major Event
- Scheduled
- Trees
- Overload
- Error
- Supply
- Equipment Malfunction
- Other
- Unknown

There is a wide variance in the industry and even within a company on the way cause codes are assigned. Those using this data to make economic decisions need to factor in the attendant error in cause code recording during their processes. The group is also exploring weather codes, isolating device codes, and failed equipment codes.

IV. SUMMARY

The TF on Distribution Reliability Indices is a very active group that continues to update and enhance the Full-Use Guide on Electric Power Distribution Reliability Indices 1366-2001. The group is always looking for more participation. If you have an interest in assisting with standards developments, please contact Cheryl A. Warren for more information.

The Guide is useful for trending reliability performance for both internal and external utility uses. Public Service Commission and customers sometimes require information about reliability performance. Utility executives set incentive goals based on reliability indices. Survey groups such as EEI use the guide as the basis for their surveys. Reliability and planning engineers use indices to track reliability performance and adjust design and operations parameters based on

performance. The indices used by the aforementioned people are defined in the Guide. In the future, the Guide is likely to be used more extensively for benchmarking and possibly for regulation.

V. ACKNOWLEDGMENT

The author gratefully acknowledges the contributions of the Task Force members. This is the most active group that the author has had the pleasure of working with and she wants to commend their activities. The task force membership includes:

John Amseough, Xcel Energy
 OC Amrhyh, OPEC
 Greg Ardrey, Alliant Energy
 Ignacio Ares, Florida Power & Light Company
 Pam Bagley, Xcel Energy
 Gene Baker, Progress Energy - Florida Power
 John Banting, Cooper Power Systems
 Jerry Batson, Alliant Energy
 Steve Benoit, Minnesota Power
 Lina Bertling, Royal Institute of Technology
 Roy Billinton, D.Sc., P.Eng., University of Saskatoon
 Dave Blew, PSE&G
 Math Bollen, Chalmers University of Technology
 Jim Bouford, National Grid
 Richard Brown, ABB
 Joe Buch, Madison Gas and Electric
 James Burke, ABB
 Ray Capra, Consultant
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 Donald M. Chamberlin, Northeast Utilities
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 Dan Durbach, Stone and Webster
 Russ Ehrlich, Conectiv
 Charlie Fajnyvandratt, NCI
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 Mahmud Fotuhi-Firuzabad, University of Saskatoon
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 Peter Gelineau, Canadian Electricity Association
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 Jeff Goh, PG&E
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 John Goodfellow, ECI
 Robert Y. Goto, Los Angeles Dept. of Water and Power
 John Grainger, University of North Carolina
 Don Hall, CES International
 Mark Halpin, Mississippi State University
 Dennis Hansen, PacifiCorp
 Randy Harlas, El Paso Electric Company
 Mostafa Hassani, PEPCO
 Harry Hayes, Ameren
 Charles Heising, Alaska Power & Telephone Company
 Eric Helt, PECO Energy (An Exelon Energy Company)
 Richard Hensel, Consumers Energy Company

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VII. BIOGRAPHIES

Cheryl A. Warren graduated from Union College in 1987 with a BSEE. She worked for Central Hudson Gas and Electric for two years in the Electric Protection Section performing distribution protection studies. In 1989, Mrs. Warren was given a fellowship at Union College to complete her MSEE degree, which she earned in 1990. She went to work for Power Technologies, Inc. (PTI) in 1990 where she worked until 1999. At PTI, Mrs. Warren worked in the distribution engineering group for five years. She managed distribution software (PSS/U and the PSS/Engines) for three years and then resumed full time consulting in reliability and power quality. Mrs. Warren joined Navigant Consulting, Inc. in 1999. She is a Principal in the Electric and Natural Gas Distribution Group where she leads reliability and distribution based engagements. Mrs. Warren chairs the IEEE WG on System Design and the Task Force on Distribution Reliability Indices. She was awarded the Technical Committee award.